

**A proposed alternative air quality modeling protocol
to examine the status of attainment of PSD Class I increments.**

(MOU Protocol)

Reflecting U.S. EPA comment
Completed April 30, 2004 per a State & EPA MOU

August 18, 2005

**Prepared by
North Dakota Department of Health
Environmental Health Section
PO Box 5520
Bismarck, North Dakota 58506-5520**

**A proposed alternative air quality modeling protocol
to examine status of attainment of PSD Class I increments.**

August 18, 2005

Prepared by
North Dakota Department of Health
Environmental Health Section
PO Box 5520
Bismarck, North Dakota 58506-5520

Points of Contact

Legal –

Lyle G. Witham, Assistant Attorney General

Administrative –

L. David Glatt, Chief of the Environmental Health Section

Terry L. O’Clair, Director of the Division of Air Quality

Technical –

Martin R. Schock, Senior Environmental Scientist

Final.

Foreword.

This document is a corrected and updated version of “A proposed alternative air quality modeling protocol to examine the status of attainment of PSD Class I increment” that is dated April 30, 2004. That version was forwarded to the U.S. Environmental Protection Agency on May 5, 2004, and is also addendum Tab “B” to the draft final version of “North Dakota’s SO₂ Air Quality Modeling Report,” which was presented to EPA in November 2004. The corrections are listed below.

Pages 10 – 12.	Captions for the two right columns were corrected. The descriptions for some CALMET control-file input variables were improved.
Pages 14 – 15.	Captions for the two right columns were corrected. The descriptions for some CALPUFF control-file input variables were improved.
Page 16.	The last paragraph was revised to include mobile sources of sulfur dioxide as contributors to the background concentrations for sulfur dioxide.
Page 19.	The PSD baseline sulfur dioxide emission rate for Unit 1 of the Stanton Station was corrected. The format of the table on this page was also revised.
Page 23.	A clarifying sentence was added to footnote 4.
Page 27.	A critical typing error in the first line of the first full paragraph was corrected.
Page 33.	Footnote “**” was corrected.
Pages 39 and 40.	The longitude and latitude coordinates of several sources were corrected; and the current stack diameter of the Tioga Gas Plant was corrected. These corrections are the same as those reported in “Revisions to pages 39 and 40 in the proposed alternative air quality modeling protocol dated April 30, 2004,” which is dated May 7, 2004.
Page 41.	Inserted subtitle and corrected footnotes.
Pages 45 and 46.	The last paragraph on page 45 and some paragraphs on page 46 were revised.

Final.

Page 47. Year 2001 sulfur dioxide emissions for GRE Stanton Unit 1 and the calculated emission factor for this unit were corrected. This correction resulted in the change on page 19.

Page 62. The last paragraph was revised, because attached data include only calculated 24-hour sulfur dioxide concentrations at sites of monitors.

----- Typing corrections.

Acknowledgments.

Several staff of the North Dakota Department of Health contributed to the development of this CALMET and CALPUFF modeling protocol. The staff and their contributions are:

Rob White	Flare and treater sulfur dioxide emissions inventories.
Tom Bachman	Power and gas plant data and sulfur dioxide emissions.
Dan Harman	Ambient monitored sulfur dioxide concentrations.
Steve Weber	Maps and modeling technical advice.

Table of Contents	Page
Executive summary.	1
1.0 Introduction.	4
2.0 CALMET control file inputs.	7
3.0 CALPUFF control file inputs.	13
4.0 Sulfur dioxide emission rates.	16
5.0 Background concentration and accuracy tests.	21
6.0 Deterioration of ambient sulfur dioxide in PSD Class I areas.	25
7.0 Summary.	29
Appendices.	
A – CALMET code revision.	31
B – Model accuracy conundrum.	32
C – Dates of source permits, startup and shutdown.	33
D – Baseline source normal operations and related source operating data.	35
E – Source specific sulfur dioxide emission factors.	41
F – Oil and gas production source inventories.	48
G – Correspondence between emissions data and monitoring data.	56
H – Monitoring data for model accuracy tests.	61
Attachments. Omitted from the corrected and updated copy.	
1 – Alternative Meteorological Data Sets for North America.	
2 – Meteorological Data Preparation for ENSR CALMET Study.	

Executive summary.

A Memorandum of Understanding between the State of North Dakota (hereafter State) and the United States Environmental Protection Agency (EPA) describes agreed-upon elements of an air quality modeling protocol when implementing Prevention of Significant Deterioration within the state under the federal Clean Air Act. This document provides many input and output details and describes some data processing methods for implementation of these elements of the modeling protocol.

Overview of elements for an alternative CALMET and CALPUFF modeling protocol.	
EPA and the State agreed that the State may:	Summary of alternative implementation action:
Use recent versions of CALMET and CALPUFF models.	Values and settings in input control files for CALMET and CALPUFF that establish the modeling domain and that govern model computations are specified.
Model the baseline emission inventory and the current emission inventory to determine estimated baseline concentrations and current concentrations, respectively, for calculating any change in air quality since the baseline and to assist in examining correspondence between modeling and monitoring in any accuracy analysis.	Two sulfur dioxide source inventories have been created; one for the PSD baseline period and another for the current period. Results of modeling the current inventory will be compared to actual observed concentrations in model accuracy tests.
Use actual emissions data from years from a different time period other than the two years preceding the minor source baseline date when that time period (two years) is more representative of normal source operations.	The baseline period normally is the two years preceding the PSD minor source baseline date; however, analysis of production or operating data revealed that operations following that date were more representative of normal source operations for some power production sources and a charcoal briquette production plant.

EPA and the State agreed that the State may:	Summary of alternative implementation action:
Use sulfur dioxide emission factors based on recent continuous emission monitoring (CEM) data, and corresponding coal consumption and coal sulfur-content data, to establish emission factors for estimating baseline emissions.	Source-specific AP-42 emission factors were determined for the units of baseline power plants. These factors and baseline coal consumption coal sulfur-content data were used to determine baseline emissions.
Use actual emissions in emission estimation procedures for short-term time periods that are consistent with the CAA and promulgated EPA and North Dakota regulations.	The State's rates are actual emissions modified by source operating hours. The baseline rates for some power plants were calculated using source-specific emission factors, amounts of coal consumed during the two years of normal operations, and the sulfur content of that coal. The current rates for these plants were calculated from CEM data.
Use five (5) years of mesoscale meteorological data such as National Weather Service upper air and hourly surface data or, alternatively, three (3) years of prognostic meteorological model (MM) data suitable for CALMET, such as advanced MM5 or Rapid Update Cycle (RUC) data.	The State has six (6) years, 1990 through 1994 and 2000, of National Weather Service (NWS) upper air and surface meteorological data. NWS upper air and surface data for years 2001 and 2002 will be assembled. The State also has three (3) years, 2000–2002, of hourly RUC2 ^d derived from RUC-2 data
Use air quality monitoring data to guide choices, when appropriate, for the modeling protocol so that modeling results achieve reasonable agreement with that data. The background sulfur dioxide concentration is a critical component of model accuracy analyses.	Model accuracy analyses will be completed. A background concentration for sulfur dioxide in the State's PSD Class I areas – during weather events causal of the higher ambient concentrations due to sources in the modeling domain – of 1.5 micrograms per cubic meter will be used for 3-hour and 24-hour model accuracy analyses.

The modeling protocol can be described as a sequence of interdependent actions. A summary of the modeling protocol is shown in the chart below. Details for each step of the protocol, except preparation of the meteorological and geophysical data and set-up of sensitivity analyses, are provided.

Summary outline of the modeling protocol.	
<p>After completing steps 1 and 2, complete step 3 if needed.</p> <p>Repeat steps 1 and 4 through 6 at right –</p> <p>for each of three years (2000, 2001, and 2002) of advanced prognostic mesoscale meteorological data, RUC2^d data, with assimilated NWS hourly surface and twice-daily upper air meteorological data.</p>	<p>Step 1.</p> <p>Prepare: A) meteorological data and geophysical data, and B) CALMET control-file input data and CALPUFF control-file input data.</p>
	<p>Step 2.</p> <p>Prepare: A) current (years 2000 and 2001) sulfur dioxide emissions inventory, and B) baseline sulfur dioxide emissions inventory.</p>
	<p>Step 3.</p> <p>Conduct model sensitivity analysis as appropriate, and adjust select control-file inputs if warranted.</p>
	<p>Step 4.</p> <p>A) Determine current concentrations for each of the PSD Class I areas (model the current sulfur dioxide emissions inventory with and without FLM CONAI sources). B) Determine the accuracy of model predicted concentrations by statistical comparison with monitored concentrations.</p>
	<p>Step 5.</p> <p>Determine baseline concentrations for each of the PSD Class I areas (model the baseline sulfur dioxide emissions inventory).</p>
	<p>Step 6.</p> <p>Compute and tabulate sulfur dioxide deterioration after PSD baseline with and without FLM CONAI sources:</p> <p>A) paired in space (each receptor) and in time. B) paired in space (each receptor) only.</p>
<p>FLM CONAI = Federal Land Manager Certification of No Adverse Impact</p>	

1.0 Introduction.

1.1 Brief background

Since 1999, the State has engaged in actions to ascertain whether the federal CAA's PSD Class I 24-hour increment for sulfur dioxide is exceeded and, if so, the amount of emitted sulfur dioxide that should be captured by controls so as to satisfy that increment. These actions dealt with several unique challenges.

It was the State's first review of the status of attainment of PSD sulfur dioxide increments that did not include a new source or source modification.

There is no existing EPA proven methodology for conducting this review either in rule or in EPA guidance.

There are no field monitoring data at the time of the PSD trigger date (6 January 1975) or the PSD minor source baseline date (19 December 1977) for western North Dakota, including the PSD Class I areas. Monitoring data are available from about 1980. The results of a draft 1999 modeling assessment of deterioration since PSD baseline were not in harmony with monitoring data.

The technology and protocol for mesoscale air quality modeling has been, and is, in flux; specifically, advances are occurring in meteorological drivers for the CALPUFF model, and comprehensive inventories of emitted sulfur dioxide were first compiled three years ago.

FLM certifications of no adverse impact were granted to several facilities in North Dakota, two of which are operating at this time. Ambient concentrations of sulfur dioxide in the North Unit of the Theodore Roosevelt National Park (TRNP), a PSD Class I area, have declined over the past twenty years.

Sulfur dioxide monitoring data from locations in Class I areas reflect all emitted sulfur dioxide, including any deterioration since PSD benchmark (baseline) years. The objective of this alternate modeling protocol is to: first, simulate current concentrations that are in reasonable harmony with available monitoring data; second, simulate baseline concentrations in a consistent manner; and third, calculate deterioration as the difference between current and baseline concentrations.

North Dakota has a long-standing history of administering provisions of the CAA under federal program primacy granted by EPA to the State. More than twenty-two years ago, North Dakota was a leader in establishing a modeling protocol for assessing compliance of proposed new sources with PSD Class I increments. The modeling protocol for mesoscale domains includes two stages of models; a

meteorological model that establishes the geographic and atmospheric domain, which is CALMET, and a pollutant transport and dispersion model, which is CALPUFF.

1.2 Document scope

Data inputs for air quality modeling include numerous input variables having a variety of purpose for computer execution of the models and for prediction of ambient concentrations of an emitted pollutant such as sulfur dioxide. The predicted concentrations can be more sensitive to the settings or values of some variables than settings or values of other variables. Some information such as weather data and terrain data must be pre-processed prior to use by the models. Conclusions regarding amounts of air quality deterioration depend on data output compilation methods. This document provides a modeling protocol as an alternative to prior protocols. It describes methods or lists settings and values related to:

- a. meteorological data inputs,
- b. CALMET control-file inputs,
- c. CALPUFF control-file inputs,
- d. current-period and baseline-period inventories of sources that emit sulfur dioxide, including emission rates,
- e. the role of model accuracy tests, including background concentration for such tests, and
- f. gauging deterioration of ambient sulfur dioxide concentrations after PSD baseline.

This document does not address all details of an alternative modeling protocol; the remaining details, such as preparation of terrain elevation, land use data, ozone data and precipitation data, will follow a May 2003 State Department of Health modeling protocol. Prominent topographic features are the Little Missouri River, the Missouri River and Lake Sakakawea.

[Note. The words predict, prediction, etc., are used throughout this document in past context, which relates to assessment of anticipated air quality impacts of proposed new sources as contributing impacts to emissions of existing, operating sources. In a periodic review, there is no proposed new source, and modeling is used to simulate the air quality impacts of existing sources.]

1.3 Basis for an alternative modeling protocol

Over the last 25 years, air quality models have been used to predict expected ground level concentrations due to source emitted pollutants. The models have advanced from crude representations of transport winds and dispersion; the advancements resulted in

improved model skill and, thus, less need for conservative assumptions so as to protect health or welfare. The State has adopted upgrades of models and modeling methods throughout the years. On occasion, the State has made contributions to those methods.

The State's protocol for use of CALMET and CALPUFF anchors to several sources of information, such as instruction provided by the CAA, PSD rules and EPA interpretive preambles and decisions by courts. In addition, IWAQM guidance, EPA guidance, FLM FLAG guidance, model user manuals and results of model sensitivity tests using input alternates may also apply.

In the past, tests of the sensitivity of CALMET and CALPUFF output to values or settings of some input control variables were completed, and some values or settings were chosen based upon test results. Some tests did not include monitoring data, and others did. Selection of model control inputs to tune, or calibrate, a model may improve agreement between model calculated data and observational data, but such choices may not improve the science of the model. Additional sensitivity tests, or diagnostic tests, may be conducted if warranted; these tests will examine the technical performance of model calculation methods and algorithms.

The State has ambient sulfur dioxide concentration data obtained with field monitors. These data are the air quality consequence of the transport, dispersion and depletion of the sulfur dioxide emitted by operating sources. Model protocol accuracy should be quantified and reported when monitoring data are available. (See section 10.1.3 of 40 CFR 51, Appendix W.) Model accuracy results that indicate over prediction of concentrations soften concern that model inputs and results are adequately conservative so as to protect health or welfare.

The second highest 24-hour ambient concentrations among all days in the South Unit of TRNP were: for year 2000, 9.39 ug/m³; 2001, 8.81 ug/m³; and 2002, 8.30 ug/m³.

The State has used its monitoring data to test the accuracy of the CALMET and CALPUFF models. Past accuracy tests demonstrate that the duo over predict the largest monitored concentrations, regardless of time of occurrence of those concentrations during the year (unpaired in time, but paired at place). However, the duo has no skill in predicting concentrations that correspond day-to-day throughout the year with monitored concentrations (paired in time as well as at place). (See also paragraph b, section 10.1.2 of 40 CFR 51, Appendix W.)

1.4 Treatment of sources granted CONAI

Prior to 2002, several proposed sources were granted FLM certifications of no-adverse impact (CONAI); two of these sources are currently operating. (See Appendix C.) Results of assessments of deterioration of ambient sulfur dioxide concentrations will be compiled without and with contributions due to the sulfur dioxide emissions of those two sources. Provisions of the CAA and PSD rules will govern interpretation of results. The FLM FLAG guidance also may apply.

2.0 CALMET control file inputs.

2.1 Meteorological data

Within the last two years, the State received three advanced hourly meteorological model data sets at 10 kilometer resolution for input to the CALMET model. The three data sets include years 2000, 2001 and 2002. The data sets were prepared by WindLogics, Inc., (formerly Software Solutions and Environmental Services Company). WindLogics captured and archived NOAA's Rapid Update Cycle version 2 (RUC-2) short-term forecast model data, which has a 40 kilometer horizontal resolution and over 40 layers of data in the vertical dimension. Because the 40 kilometer horizontal resolution is typically insufficient in coastal and mountainous regions, WindLogics adapted the ARPS Data Assimilation System (ADAS) to assimilate hourly surface weather data and terrain data with the RUC-2 data and to extrapolate these data to a 10 kilometer horizontal resolution in a format compatible with the MM5 data ingest capability of CALMET. For this protocol, the resulting data are labeled RUC2^d. [Note. For information on RUC and other large scale meteorological data sets, see Attachment 1 and <http://maps.fsl.noaa.gov/>, <http://www.nws.noaa.gov/om/tpb/448body.htm> and <http://www.meted.ucar.edu/nwp/pcu2/rucvres2.htm>. For information on ADAS, see <http://www.caps.ou.edu/ADAS.html>. For descriptions of the adaptation of RUC-2 for CALMET by WindLogics, see Attachment 2 and its report "RUC Analysis-based CALMET Meteorological Data for the State of North Dakota."]

EPA and IWAQM have promoted two-tier air quality assessment protocols. Tier one is less rigorous but provides conservative results. When results indicate compliance with standards, such as the NAAQS, no further analysis is pursued. However, when results indicate apparent non-compliance, a more robust and rigorous tier-two analysis is undertaken. In this context, the State will use the three years of RUC2^d data, rather than five years of NWS twice-daily upper air and hourly surface meteorological data, to refine modeling assessments of air quality deterioration. No MM4 data will be used.

The State has six (6) years, 1990 through 1994 and 2000, of NWS twice-daily upper air and hourly surface meteorological data for an area that is larger than the modeling domain. The locations of stations where the data were collected during year 2000 are shown on an attached map. In addition, NWS mesoscale meteorological data for years 2001 and 2002 will be assembled. The data for years 2000, 2001 and 2002 will be used with RUC2^d data in Step 2 CALMET wind field computations.

2.2 CALMET code revision

CALMET meteorological model version 5.5 will be used. CALMET extrapolates surface winds to upper layers in two steps. The CALMET code has been revised as shown in Appendix A for use only when applying NWS twice-daily upper air and hourly surface

data without prognostic meteorological data so that surface data are not vertically extrapolated in Step 2 wind field calculations, because Step 2 wind field computations do not use BIAS values that vertically dampen the influence of surface winds in calculation of upper air winds as do Step 1 computations. [Note. The software change applies only to application of CALMET on State modeling problems and only when using NWS twice-daily upper air and hourly surface data, and it may not be universally applicable.]

2.3 Control file inputs

Several CALMET control file inputs describe the geographic and atmospheric domain for air quality simulation modeling. The domain must spatially reflect locations of PSD Class I areas, locations of sources of sulfur dioxide emissions that impact ambient sulfur dioxide concentrations in those areas, and the weather that transports and disperses sulfur dioxide from those sources.

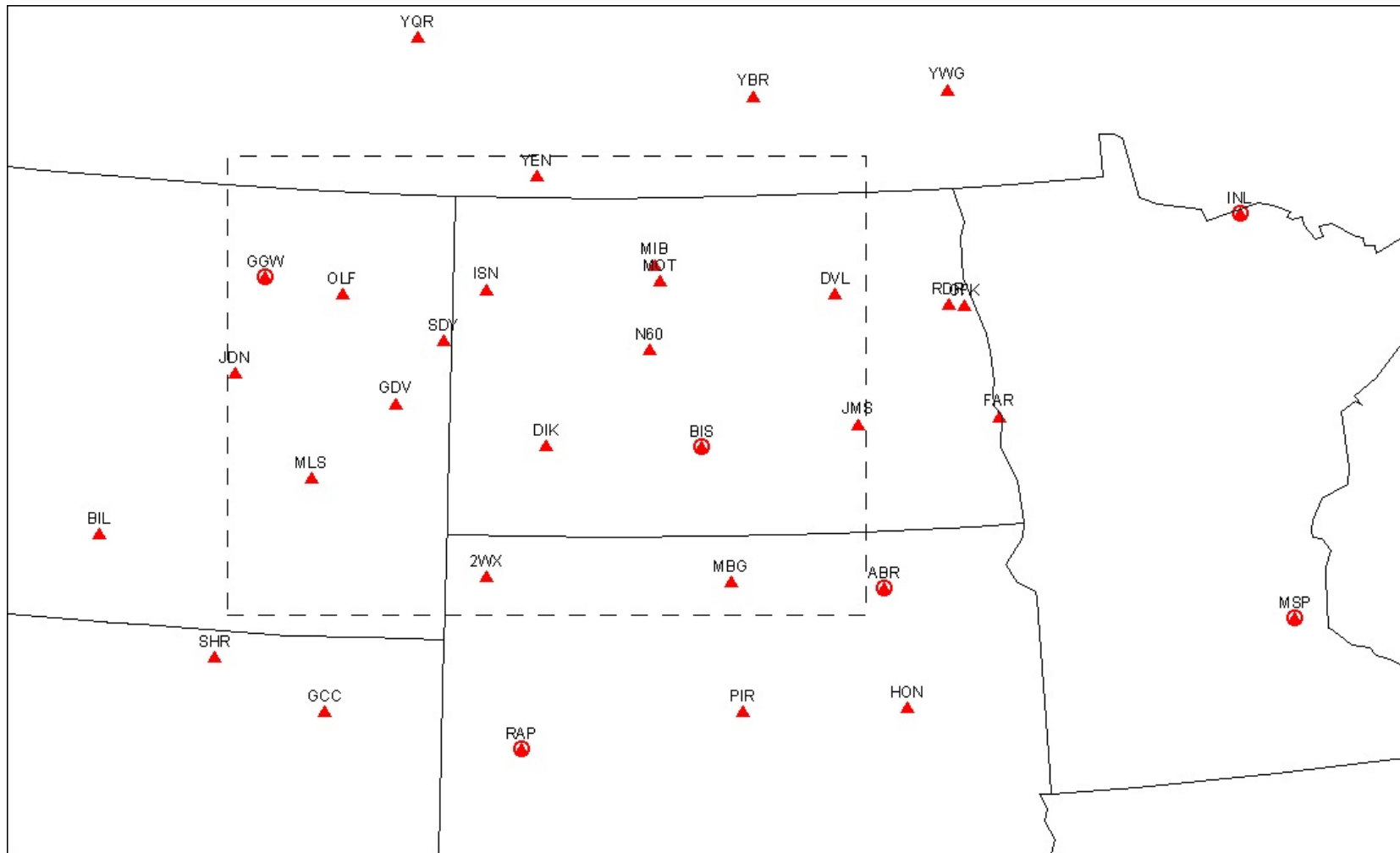
Control file inputs also govern use and interpretation of terrain data, weather data and other descriptors of the selected domain. An attached table shows those CALMET control-file inputs that are uniquely appropriate for the State's geographic and atmospheric modeling domain, as well as inputs for computation of gridded wind fields that govern transport of emitted sulfur dioxide. The dimensions of the modeling domain are 640 kilometers west-east and 460 kilometers south-north. Because this domain is large, a Lambert Conformal grid and Lambert Conformal Coordinates for locations of meteorological and precipitation stations will be used.

The right column in the attached table describes the alternative CALMET inputs when using RUC2^d (shown as "RUC") data. Another column in this table describes alternative CALMET inputs when using only NWS twice-daily upper air and hourly surface mesoscale meteorological data. All other required CALMET control file inputs follow IWAQM recommended default values or settings.

The approximate heights above ground level at Bismarck for the 850, 700 and 500 millibar pressure altitudes of the standard atmosphere are, respectively, 500, 2,500 and 5,000 meters. The National Weather Service uses rawinsondes to twice-daily measure upper air winds at these and other pressure altitudes. In addition, the stack heights of sources, other than oil and gas production sources, range from 20 meters to 200 meters above ground level. Therefore, alternative values for variable ZFACE, which is the tops of twelve wind field layers, are set at 20, 50, 90, 140, 200, 270, 370, 500, 1000, 1700, 2500 and 4200 meters. The bottom of the lowest layer is 0 meters. The highest ZFACE level is 200 meters above the height of variable ZIMAX, which is the maximum over land mixing height.¹

¹ The maximum mixing height of the upper Great Plains is 4,000 meters. (Holzworth, 1972. Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution throughout the Contiguous United States. EPA Publication No. AP-101, Office of Air Programs.)

Twice-daily upper air and hourly surface meteorological stations for year 2000.



- ▲ Surface Station
- ⬮ Surface + Upper-air Station

CALMET user defined and non-IWAQM control-file inputs.				
Variable	Type	Description	Alternative NWS only	Alternative RUC & NWS
NUSTA	integer	number of upper air stations within and surrounding the modeling domain – may change from year to year	6	6
1BTZ	integer	base time zone (7 = Mountain Standard)	7	7
NX	integer	number of grid cells in X direction	128	213
NY	integer	number of grid cells in Y direction	92	153
NZ	integer	number of vertical layers	12	12
DGRIDKM	real	horizontal/vertical size of one grid cell (km)	5.	3.
XORIGKM	real	reference LCP (Lambert Conformal Projection) X coordinate of southwest grid cell (km)	-380.	-380.
YORIGKM	real	reference LCP Y coordinate of southwest grid cell (km)	140.	140.
XLAT0	real	latitude at southwest corner of grid cell 1,1 (deg.)	45.152	45.152
XLON0	real	longitude at southwest corner of grid cell 1,1 (deg.)	106.848	106.848
ZFACE	real array: NZ + 1	cell face heights (m)	0., 20., 50., 90., 140., 200., 270., 370., 500., 1000., 1700., 2500., 4200.	same as NWS only at left
LLCONF	logical: T = True	if T, use LCP map coordinates and rotate winds from true north to map north	T	T
XLAT1	real	latitude for 1 st standard parallel for LCP (deg)	46.0 ¹	46.0 ^{1, 3}
XLAT2	real	latitude for 2 nd standard parallel for LCP (deg)	48.5 ¹	48.5 ^{1, 3}
RLON0	real	reference longitude for LCP rotation of input winds (deg)	102.0 ²	102.0 ^{2, 3}

Variable	Type	Description	Alternative NWS only	Alternative RUC & NWS
RLAT0	real	origin latitude for LCP rotation of input winds (deg)	44.0 ²	44.0 ^{2, 3}
NSSTA	integer	number of surface meteorological stations within and near the modeling domain – may change from year to year	32	32
NPSTA	integer	number of precipitation stations within and near the modeling domain – may change from year to year	89	89
IKINE	integer	if 0 (IWAQM default), kinematic effects (a wind field option) are not computed	0	0
IEXTRP	integer	extrapolate surface winds to upper layers: 1 or -1 = no extrapolation; 4 or -4 (IWAQM default) = use similarity theory;	-4	-4
BIAS	real array: one value for each of NZ layers	layer-dependent biases modifying the weights of surface and upper air stations (-1. =<BIAS<=+1.): negative bias reduces weight given upper air data, positive bias reduces weight given surface data, zero bias leaves weights unchanged	Step 1 only: -1.0, -0.9, -0.7, -0.4, 0.0, 0.3, 0.7, 1.0, 1.0, 1.0, 1.0, 1.0	do not apply
IPROG	integer	if 0, gridded prognostic model field winds are used: if 14, use MM5.DAT file as initial guess field and, if 15, use the file as observations	0	14
LVARY	logical: T = True, F = False	if F (IWAQM default), interpolation of winds at a grid point does not include met station observations located beyond RMAX1 or RMAX2 or RMAX3	F	F
RMAX1	real	max. radius of influence over land in the surface layer (km)	200.	100.
RMAX2	real	max. radius of influence over land in layers aloft (km)	800.	200.
RMAX3	real	max. radius of influence over water (km)	800.	200.

Variable	Type	Description	Alternative NWS only	Alternative RUC & NWS
TERRAD	real	radius of influence of terrain features (km) (note: slope flow is computed when default for variable ISLOPE is 1)	16. (coordinated with DGRIDKM)	10. (coordinated with DGRIDKM)
R1	real	in the surface layer, the distance (km) from an observation station at which the wind observation and the first guess field are equally weighted	16.	10.
R2	real	in the upper layers, applied same as R1	46.	
ISURFT	integer	surface station number used for the surface temperature for the diagnostic wind field module	12 (Bismarck)	12 (Bismarck)
IUPT	integer	upper air station number used to compute the domain-scale temperature lapse rate for the diagnostic wind field module	1 (Bismarck)	1 (Bismarck)
ZUPWND	real array	bottom and top of layer through which the initial guess winds are computed (m)	1., 2500.	not used
ZIMAX	real	maximum over land mixing height (m)	4000.	4000.
ZIMAXW	real	maximum over water mixing height (m)	4000.	4000.
MNMDAV	integer	maximum search distance (in grid cells) in back trajectory averaging of mixing heights & temperatures (note: defaults for variables IAVEZ1 and IAVET are 1)	6	7
ILEVZI	integer	layer of winds used in upwind averaging of mixing heights (no default specified in the model)	3	3
footnotes: 1. The first standard parallel at 46 degrees latitude is north of, but near, the southern border of North Dakota; the second standard parallel at 48.5 is south of the northern border of the state; thus, providing a balanced inclusion of the modeling domain. 2. The approximate center of the TRNP/power-plant region is 47.35 degrees latitude and 102 degrees longitude (the LCP map Y-axis parallels true North at RLON0). 3. RUC2 ^d was constructed suitable for CALMET ingest as MM5 with the center latitude at 47.35 degrees, the center longitude at 103 degrees, the first standard parallel at 47.34 degrees latitude and the second at 47.36 degrees.				

3.0 CALPUFF control file inputs.

CALPUFF transport and dispersion model version 5.7 will be used. Several CALPUFF control file inputs govern calculation of atmospheric transport, dispersion and depletion of the sulfur dioxide emitted by the sources in the modeling domain and, thus, assessment of deterioration (or improvement) of ambient sulfur dioxide concentrations in the PSD Class I areas.

An attached table shows those CALPUFF control file inputs that are uniquely appropriate for the State's Class-I-area modeling domain established by CALMET. The right columns in this table describes the inputs for alternative use of CALPUFF. All other required CALPUFF control file inputs follow IWAQM recommended default values or settings. Because the modeling domain is large, a Lambert Conformal grid and Lambert Conformal Coordinates for locations of sources will be used.

In addition, the east end of the meteorological grid was truncated for plume computational domain (IECOMP), because plumes that first travel east and then circle west to PSD Class I areas could travel distances greater than 300 kilometers. The south and north sides of the meteorological grid were truncated for the computational domain, variables JBCOMP and JECOMP respectively, so as to reflect CALMET variables R1, R2 and MNMDAV. The west side of the meteorological grid was not truncated for the computational domain, variable IBCOMP, due to the sources located near the west end of the grid.

Input control variable IVEG selects one of three algorithms for calculation of surface canopy resistance, which is a component of dry deposition. During the months of April through September (Julian days 91 through 273 in tables attached to Appendix H), vegetation in central and western North Dakota likely is active and unstressed or stressed. During the remainder of the year, vegetation likely is inactive. The highest sulfur dioxide concentrations occur in nearly equal proportion during the two calendar seasons. (See tables attached to Appendix H.)

Background ozone data will be assembled into an input file (OZONE.DAT) as hourly ozone concentrations throughout the year from monitoring stations located in the TRNP-SU, at rural Dunn Center, at rural Hannover and/or near Beulah. One file will be assembled for each year of modeled meteorological data. When background ozone data are missing, the default concentration will be the value of variable BCKO3.

CALPUFF user defined and non-IWAQM control-file inputs.				
Variable	Type	Description	Alternative NWS only	Alternative RUC & NWS
IBCOMP	integer	southwest X-index of computational domain	1	1
JBCOMP	integer	southwest Y-index of computational domain	4	6
IECOMP	integer	northeast X-index of computational domain	122	201
JECOMP	integer	northeast Y-index of computational domain	89	148
MTRANS	integer	if 1 (IWAQM default), transitional plume rise modeled	1 for all sources	1 for all sources
MTIP	integer	if 1 (IWAQM default), stack tip down wash modeled	1 for all sources	1 for all sources
MSHEAR	integer	if 0 (IWAQM default), vertical wind shear above stack tip not modeled in plume rise	0 for all sources	0 for all sources
MSPLIT	integer	if 1, allows puff splitting; if 0 (IWAQM default), no puff splitting // set as 0 for all oil & gas production sources	1 (0 as noted)	1 (0 as noted)
MDISP	integer	if 2, horizontal and vertical dispersion coefficients calculated using micro meteorological variables	2	2
MPDF	integer	if 1, probability distribution function for vertical dispersion under convective conditions used	1	1
XLAT	real	reference latitude of the center of the modeling domain used in solar elevation angle calculations (deg)	47.3	47.3
XLONG	real	reference longitude of the center of the modeling domain (deg)	102.	102.
XTZ	real	reference time zone of the center of the modeling domain	7.	7.

Variable	Type	Description	Alternative NWS only	Alternative RUC & NWS
LSAMP	logical; F = False T = True	if F (IWAQM default), an internally calculated array of gridded receptors is not used [may set to T for select sensitivity tests, boundaries of the array would include all state Class I areas]	F	F
IVEG	integer	set to 2 when vegetation in unirrigated areas is active and stressed (IWAQM default = 1 when active and unstressed)	2	2
MOZ	integer	if 1 (IWAQM default), use hourly ozone concentrations from OZONE.DAT file	1	1
BCKO3	real	default background ozone concentration (ppb)	30.	30.
BCKNH3	real	background ammonia concentration (ppb)	2.	2.
XSAMLEN	real	maximum travel distance of puff (in grid units, one unit equals DGRIDKM) during one sampling step	0.6	1.0
XMAXZ1	real	maximum mixing height (m)	4000.	4000.
IRESPLIT	integer array	when set to 1, allows puff splitting for those hour(s) of day when nocturnal shear (e.g., low-level jet) occurs; other hours set to 0	hours 00–04 and 19–23 = 1	hours 00–04 and 19–23 = 1
ROLDMAX	real	vertical puff splitting allowed only when the ratio of last hour's mixing height to max. mixing height experienced by the puff is smaller than this value (IWAQM default = 0.25)	0.33 when coordinated with ZISPLIT, previous max. mix. height = or > 300 m	
BDOWN	real	if 0, building down wash is not modeled	0.	0.
SIGMAYI	real	initial plume (puff) sigma-y at release from source (m); if < 1.0, CALPUFF code resets to 1.0 // omit for oil & gas production sources (CALPUFF code defaults to 1.0)	1/4 the stack diameter (omit as noted)	1/4 the stack diameter (omit as noted)
NREC	integer	number of non-gridded receptors	104	104

4.0 Sulfur dioxide emission rates.

Sources within the modeling domain that emit sulfur dioxide are geographically dispersed across western North Dakota and eastern Montana. Only those sources located in the western one-half of North Dakota and major sources located in eastern Montana were included in emissions inventories. The sources include coal-fired electricity generating plants, a synthetic natural gas production plant, natural gas processing plants, oil refineries, a charcoal briquette production plant and oil and gas production sources.

Some sources were constructed prior to the PSD trigger date (6 January 1975); some of these sources were retired after the PSD minor source baseline date (19 December 1977), and others are still operating. Some sources were constructed and began operating after the PSD minor source baseline date. A map of these sources is attached, and date data for these sources are provided in Appendix C.

Two sulfur dioxide source inventories have been created; one for the PSD baseline period and another for the current period. Twenty-two years separate the PSD baseline period and the current period. Sources constructed and operating after PSD baseline do not contribute to PSD baseline-period ambient concentrations. Sources that were retired after the minor source baseline date do not contribute to current-period ambient concentrations.

The baseline period normally is the two years preceding the PSD minor source baseline date. However, analysis of annual production or operating data revealed that operations for years following that date were more representative of normal source operation for some power production sources and the charcoal briquette production plant. For example, annual utilization of rated heat input capacity of coal-fired combustion systems of power plants can be determined from amounts of coal burned and the heat value of that coal. (See Appendix D.)

The current period is the two-year period preceding the date of concern; the two years are 2000 and 2001, except that only year 2000 will be used for oil and gas production sources. The baseline inventory includes more than 850 oil and gas production sources (flares and treaters), and the current inventory includes more than 550 of these sources. (See Appendix F.)

Some sources that are located within the modeling domain but not modeled contribute to the background sulfur dioxide concentration; these sources are mobile sources, oil and gas production sources in North Dakota located beyond 50 kilometers from Class I areas, and oil and gas production sources having sulfur dioxide emission rates less than 0.001 gram per second. Other sources that are outside the domain also contribute to the background sulfur dioxide concentration; these sources are mobile sources, heating plants and commodity processing plants in eastern North Dakota, sources in central and western Montana, and sources in Minnesota, South Dakota and southern Saskatchewan.

Instruction for representation of rates of emitted sulfur dioxide is provided by PSD rules and by EPA regulations (interpretive preambles). Rates as actual emissions, which is a term defined in PSD rules, provide consistent and comparable rates among all sources, including oil and gas production sources, and between both time lines (baseline and current period).

The sulfur dioxide emission rate for lignite-fired boilers is a function of the amount of coal burned and the sulfur content of that coal, as well as any natural sulfur dioxide scrubbing agents in that coal and boiler performance. Rather than using the AP-42 emission factor of 30S for power plants, an emission factor was calculated for each unit of power plants that does not have a sulfur dioxide emission control system. (See Appendix E.) The factors are a mass-balanced calculation between annual emissions from recent continuous emissions monitoring (CEM) system data and corresponding coal consumption and coal sulfur-content data. The factors were then used to calculate baseline rates using baseline-period coal consumption and coal sulfur-content data.

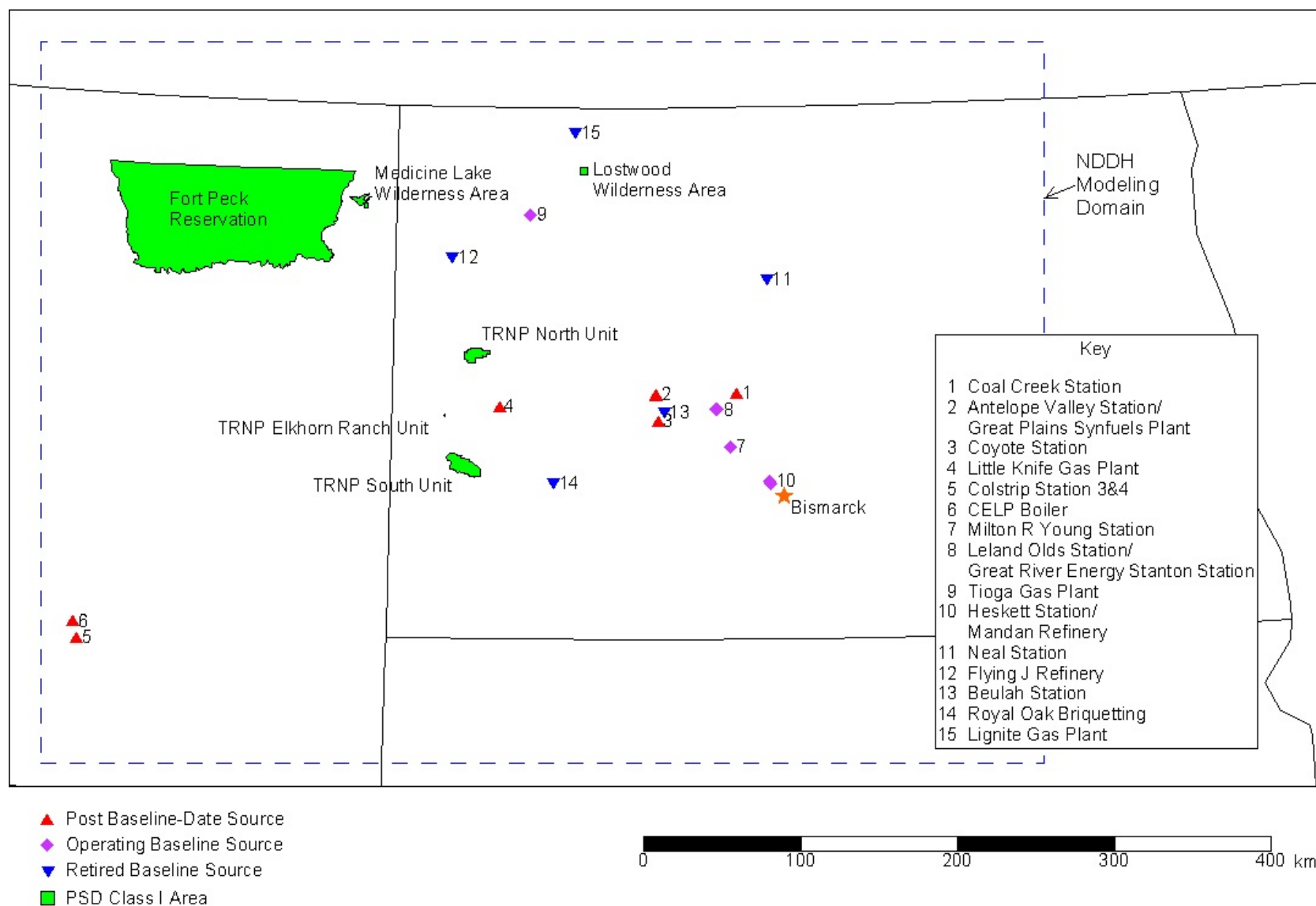
An attached table shows estimated baseline sulfur dioxide emission rates for all sources except oil and gas production sources. The sources of data for computation of baseline rates are shown, and the rates are actual emissions as annual emissions averaged over operating hours. The rates in the right column are based upon the sulfur content of coal consumed during the two-year period representing normal source operations. The right column in this table provides the baseline rates for alternative modeling.

Another attached table shows 2000 - 2004 sulfur dioxide emission rates for all sources, except oil and gas production sources. The sources of data for computation of rates are shown, and the rates as actual emissions are computed as annual emissions averaged over operating hours. The right column in this table provides current-period rates for alternative modeling. The right column data include the two sources granted certifications of no-adverse impact by the Federal Land Manager.

Source locations in the modeling domain and source stack parameters are listed in Appendix D. These locations and parameters also are CALPUFF input data. Similar data for the numerous oil and gas production sources are not shown. Several sources have two or more points (e.g., stacks) of emitted sulfur dioxide. In these instances, stack data for each point are model inputs, except the same pair of coordinates for the location of each point of emitted sulfur dioxide at some retired sources has been used. Thus, emitted plumes at these sources as modeled are not horizontally separated as were the actual stacks.

[Note. The PSD minor source baseline date for sulfur dioxide for the Medicine Lake Wilderness Area (MLWA), a PSD Class I area in eastern Montana, is 26 March 1979, or about fifteen months later than such date for the North Dakota Class I areas. The baseline date for the Fort Peck Class I area follows 9 April 1984, when the non-federal re-designation became effective. Results of modeling with the sulfur dioxide emissions inventories provided by this protocol may trigger a refined analysis with emissions inventories reflecting baseline dates for these Montana areas.]

CALMET and CALPUFF modeling domain, including PSD Class I areas and sulfur dioxide source locations.



Sulfur dioxide emission rates of sources operating at the time of the PSD minor source baseline date.								
	Source	Unit	Basis	Baseline period	Ave. per.	Rate	Units	
Sources operating at PSD baseline and retired prior to current period. (See Appendix C.)	Beulah Power Plant	1 & 2	e.i.r.	76 - 77	an.ave.	127.0	lb/op-hr	#
		3, 4 & 5	e.i.r.	76 - 77	an.ave.	203.6	lb/op-hr	#
	Neal Station	1 & 2	e.i.r.	76 - 77	an.ave.	364.6	lb/op-hr	#
	Royal Oak Briquetting Plant	Boilers 1, 2 & 3	e.i.r.	78 - 79	an.ave.	220.8	lb/op-hr	
	Williston Refinery	Carbonizer Furnaces	e.i.r.	78 - 79	an.ave.	1,124.8	lb/op-hr	#
		All units	e.i.r.	76	an.ave.	51.7	lb/op-hr	
		Preflash Heater		76	an.ave.	7.1	lb/op-hr	
		Crude Heater		76	an.ave.	7.7	lb/op-hr	
		Thermal Cr. Heater		76	an.ave.	0.3	lb/op-hr	
		Charge Heater		76	an.ave.	0.1	lb/op-hr	
		Reformer Heater		76	an.ave.	0.5	lb/op-hr	
		Boiler 1		76	an.ave.	10.5	lb/op-hr	
		Boiler 2		76	an.ave.	10.5	lb/op-hr	
		Boiler 3		76	an.ave.	15.0	lb/op-hr	
Sources operating at PSD baseline and also operating during current period. (See Appendix C.)	R.M. Heskett Station	1	e.i.r.	76 - 77	an.ave.	415.8	lb/op-hr	#
		2	e.i.r.	76 - 77	an.ave.	969.9	lb/op-hr	#
	Leland Olds Station	1	e.i.r.	77 - 78	an.ave.	3,609.8	lb/op-hr	#
		2	e.i.r.	77 - 78	an.ave.	7,312.4	lb/op-hr	#
	M.R. Young Station	1	e.i.r.	78 - 79	an.ave.	4,357.0	lb/op-hr	#
		2	e.i.r.	78 - 79	an.ave.	4,726.5	lb/op-hr	+
	Stanton Station	1	e.i.r.	78 - 79	an.ave.	2,271.3	lb/op-hr	#
	Tioga Gas Plant	SRU Incinerator	e.i.r.	77	an.ave.	1,107.1	lb/op-hr	
	Lignite Gas Plant	SRU Incinerator	e.i.r.	76 - 77	an.ave.	285.8	lb/op-hr	
	Mandan Refinery	Boilers 1, 2 & 3	e.i.r.	76 - 77	an.ave.	622.6	lb/op-hr	
		Crude Furnace	e.i.r.	76 - 77	an.ave.	550.1	lb/op-hr	
		FCCU	e.i.r.	76 - 77	an.ave.	1,135.8	lb/op-hr	
		Alkylation Unit	e.i.r.	76 - 77	an.ave.	160.3	lb/op-hr	
		Ultraformer Furnaces	e.i.r.	76 - 77	an.ave.	15.3	lb/op-hr	
Total =						29,683.9		
e.i.r. = annual emissions inventory reports			lb/op-hr = pounds per operating hour					
Ave. per. = averaging period			# = rate based on source specific emission factor (Appendix E)					
an.ave. = actual emissions during operating hours			+ = rate based on annual heat input and permit allowed rate of 1.2 lbSO ₂ /mBtu					

Sulfur dioxide emission rates of sources operating during the current period (years 2000 and 2001).							
	Source	Unit	Basis	Current period	Ave. per.	Rate	Units
Sources operating at PSD baseline and also operating during current period. (See Appendix C.)	R.M. Heskett Station	1	e.i.r., CEM	00 - 01	an.ave.	248.0	lb/op-hr
		2	e.i.r., CEM	00 - 01	an.ave.	612.7	lb/op-hr
	Leland Olds Station	1	e.i.r., CEM	00 - 01	an.ave.	4,179.2	lb/op-hr
		2	e.i.r., CEM	00 - 01	an.ave.	8,145.1	lb/op-hr
	M.R. Young Station	1	e.i.r., CEM	00 - 01	an.ave.	5,161.4	lb/op-hr
		2	e.i.r., CEM	00 - 01	an.ave.	4,353.2	lb/op-hr
	Stanton Station	1 & 10	e.i.r., CEM	00 - 01	an.ave.	2,389.8	lb/op-hr
	Tioga Gas Plant	SRU Incinerator	CEM	00 - 01	an.ave.	300.6	lb/op-hr
	Lignite Gas Plant	SRU Incinerator	CEM	00 only	an.ave.	105.6	lb/op-hr
	Mandan Refinery	Boilers + Crude Furnace	e.i.r.	00 - 01	an.ave.	133.0	lb/op-hr
		FCCU	e.i.r.	00 - 01	an.ave.	1,026.9	lb/op-hr
		Alkylation Unit	e.i.r.	00 - 01	an.ave.	7.7	lb/op-hr
		Ultraformer Furnaces	e.i.r.	00 - 01	an.ave.	15.9	lb/op-hr
Sources constructed after PSD baseline and operating during current period. (See Appendix C.)		SRU Incinerator	e.i.r.	00 - 01	an.ave.	45.3	lb/op-hr
	Coal Creek Station	1	CEM	00 - 01	an.ave.	3,368.1	lb/op-hr
		2	CEM	00 - 01	an.ave.	2,972.8	lb/op-hr
	Antelope Valley Station	1	CEM	00 - 01	an.ave.	1,590.8	lb/op-hr
		2	CEM	00 - 01	an.ave.	1,496.0	lb/op-hr
	Coyote Station	1	CEM	00 - 01	an.ave.	3,955.4	lb/op-hr
	Grasslands Gas Plant	SRU Incinerator	CEM	00 - 01	an.ave.	113.4	lb/op-hr
	Little Knife Gas Plant	SRU Incinerator	CEM	00 - 01	an.ave.	80.1	lb/op-hr
	Great Plains Synfuels	Main stack	CEM	00 - 01	an.ave.	1,094.4	lb/op-hr
		Start-up flare	allowable	00 - 01	an.ave.	119.0	lb/op-hr
		Main flare	e.i.r.	00 - 01	an.ave.	184.0	lb/op-hr
		Back-up flare	allowable	00 - 01	an.ave.	78.0	lb/op-hr
	PPL Corp Colstrip	3	CEM	00 - 01	an.ave.	742.9	lb/op-hr
		4	CEM	00 - 01	an.ave.	719.0	lb/op-hr
	CELP Colstrip		CEM	00 - 01	an.ave.	419.8	lb/op-hr
Total =						43,658.2	
e.i.r. = annual emissions inventory reports							
Ave. per. = averaging period			fn 1 = began injecting sour gas during August 2002				
an.ave. = actual emissions during operating hours			fn 2 = began injecting sour gas during March 2002				
lb/op-hr = pounds per operating hour			fn 3 = see Appendix E				

5.0 Background concentration and accuracy tests.

5.1 Orientation

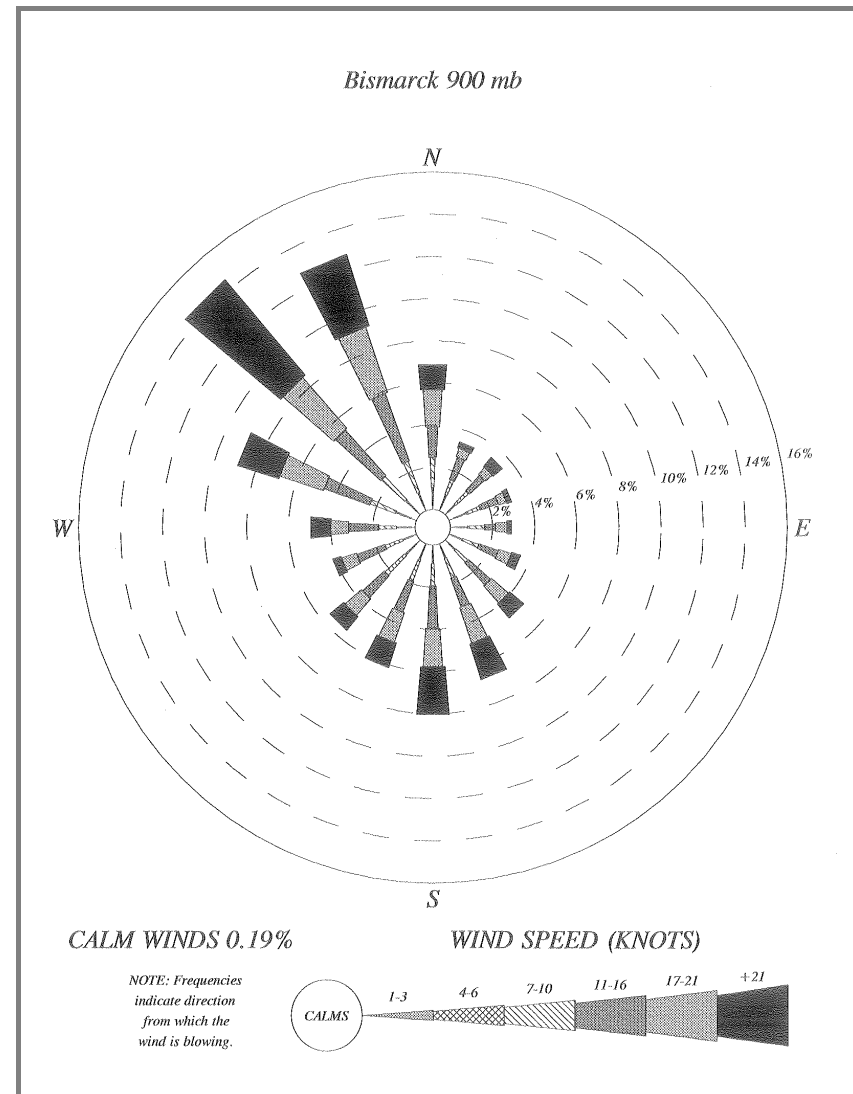
Since some sources of emitted sulfur dioxide within the modeling domain and sources outside that domain are not included in model predicted concentrations, a background concentration representing those sources must be added to model predicted concentrations when comparing those concentrations with real concentrations obtained with monitors. (See Appendix B.)

Based upon monitoring data obtained in the North and South Units of the TRNP, the highest daily concentrations of sulfur dioxide usually occur during the months of November, December, January and February. (See tables attached to Appendix H.) Modeling indicates that utility sources, which are the larger emitters of sulfur dioxide, account for most of the largest predicted concentrations in TRNP.

The occurrences of the largest concentrations are due to transport winds originating east and southeast of the modeling domain. The wind rose shown at right for the 900-millibar pressure altitude at Bismarck demonstrates the low frequency of winds occurring from the east and southeast.

5.2 Probable background concentration

Magnitudes of background concentrations likely vary with origin of the boundary layer of the troposphere that migrates over western North Dakota. The boundary-layer pool of background sulfur dioxide likely includes a broad region east through south of the modeling domain where many sources are located. For



example, the background concentration could be determined with a sulfur dioxide monitor located in the vicinity of Wilton, North Dakota, that has the technology to detect low ambient concentrations in air prior to the transport of that air westward through coal county where sulfur dioxide is emitted. (See Appendices G and H.) The background concentration represents that sulfur dioxide in the air at the time when, and the places where, those sources in the emissions inventory emit sulfur dioxide. Any sources that are not in an emissions inventory contribute to the background concentration when their plumes of sulfur dioxide co-mingle with the plumes of sulfur dioxide from sources that are in the inventory. Monitoring instruments obtain data on total actual ambient sulfur dioxide; thus, monitoring data represent the sum of both contributions of sulfur dioxide.

Some sources having stacks are located in eastern North Dakota and southern Minnesota. Another source, located in northeastern South Dakota, does not have sulfur dioxide emission control. Ground level emissions of sulfur dioxide occur from combustion of diesel fuel by non-agricultural and agricultural machinery, trucks and other vehicles. These ground level emissions occur throughout the state, but likely are more prominent in the eastern one-half of the state and regions east through south of there.

Near vertically uniform concentrations of stack emitted sulfur dioxide within the boundary layer occur downwind of sources at distances greater than 300 kilometers (about 190 miles). The ambient concentration at that distance due to a typical, uncontrolled source that emits about 4,000 pounds per hour would be about 1.9 parts per billion less depletion due to photochemical oxidation, deposition and convective vertical transport above the boundary layer. The photochemical oxidation rate for transformation of sulfur dioxide to sulfate varies from 0.5 percent per hour to 2 percent per hour; the lower rates occur during winter. One older study demonstrated that sulfur dioxide can be transported from the Ohio River Valley into southern Minnesota (study citation not available). The Minnesota Pollution Control Agency indicates that background sulfur dioxide levels in ambient air are as low as 1 part per billion. (See <http://www.pca.state.mn.us/air/emissions/so2.html>.) One part per billion equals 2.6 micrograms per cubic meter (ug/m³).

The Department of Health obtains actual observations of sulfur dioxide at several locations within North Dakota. (See Appendix H.) An estimate of the background concentration in the western region of the state can be calculated by extrapolation of the observations to hours when concentrations were less than the lower detection level of the monitoring instrument. The monitoring sites at rural Hannover and rural Dunn Center were chosen to estimate the background concentration because hourly concentrations greater than the instrument's lower detection limit occur more frequently there than at sites in Class I areas. For example, hourly concentrations greater than 1.5 parts per billion occurred during 19.4 percent of all hours during years 2000 and 2001 at the rural Hannover site, 13.8 percent of all hours at the rural Dunn Center site and 10.2 percent of all hours at the site located in the South Unit of TRNP.

The graph on the next page illustrates a power curve extrapolation of actual hourly sulfur dioxide data from the rural Hannover site, the rural Dunn Center site and the TRNP-South Unit site to probable concentrations less than 1.5 parts per billion (3.96 ug/m³) for

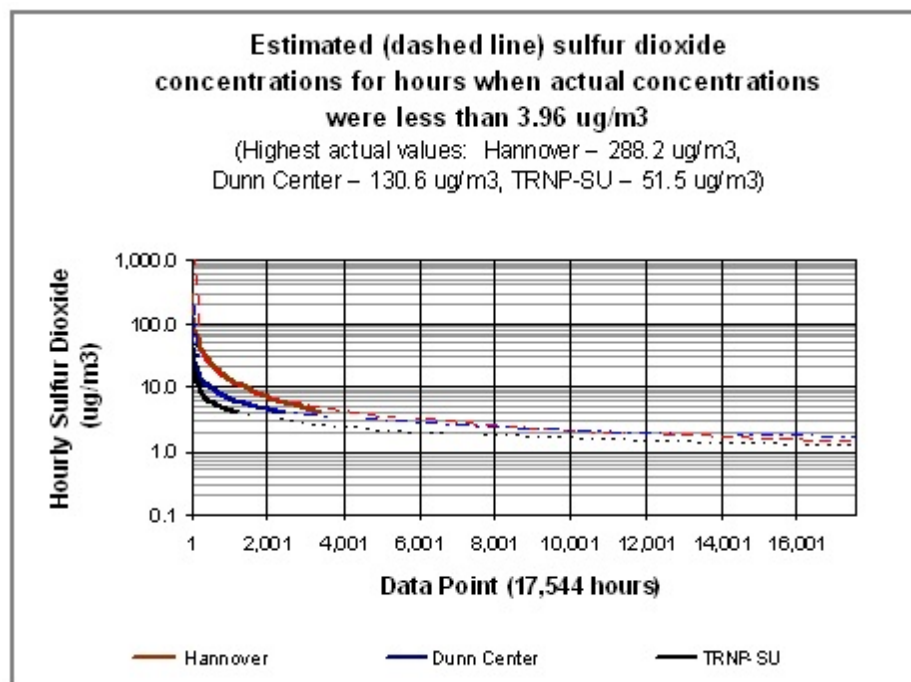
remaining hours of the two years. All hours of the actual sulfur dioxide data greater than 1.5 parts per billion were used regardless of wind direction.²

In summary, the background concentration for sulfur dioxide in the State's PSD Class I areas – during weather events causal of the higher Class-I-area ambient concentrations due to sources in the modeling domain – is likely in the range from 1 to 2 micrograms per cubic meter. A background concentration for sulfur dioxide of 1.5 micrograms per cubic meter will be used for 3-hour and 24-hour model accuracy analyses.³

5.3 Preliminary accuracy test results

People who develop models and who use models have an obligation to quantify correspondence between model predicted concentrations and actual observations of air quality. (For example, see section 10.1.3 of 40 CFR 51, Appendix W.) Thus, model accuracy tests will be completed.

Preliminary CALMET-CALPUFF accuracy tests of model predicted concentrations have been completed using past input values, settings and data.⁴ Sulfur dioxide emission rates were based upon actual emissions that represent operating hours. Peak model



² Monitor concentrations less than 1.5 parts per billion are unsuitable for estimating background concentrations. (See Appendix H.)

³ Normally, the method for statistical averaging of hourly monitoring data for 3-hour or 24-hour averaging periods substitutes ½ of 1 part per billion for those hours when no sulfur dioxide was detected. In this case, ½ of 1 part per billion, or 2.62 ug/m3, is 1.31 ug/m3.

⁴ In 1999, 2002 and 2003, the Department of Health completed and reported accuracy analyses related to PSD increment attainment; however, no background concentration was included in these analyses. Subsequently, the Department examined and reported accuracy tests to illustrate improved model accuracy using RUC2^d data. All of these tests used hourly CEM sulfur dioxide emission rates when available.

Preliminary ratios of model predicted concentrations to actual observations for year 2000.		
Background concentration (ug/m3)	Current-period sulfur dioxide inventory	
	with conventional meteorological data	with RUC2 ^d meteorological data
2.0	1.52 *	1.18 *
* Numbers are an average of 25 ratios of the 25 highest predicted 24-hour concentrations to the respective 25 highest observed 24-hour concentrations. (See also paragraph b, section 10.1.2 of 40 CFR 51, Appendix W.)		

predicted concentrations at receptor number 38 were compared to peak monitored concentrations obtained from a site in the South Unit of the TRNP. This procedure is necessary as models are unable to predict the exact time as well as location where peak impacts will occur. Model predicted concentrations were larger than monitored concentrations. Results of these tests are shown in the table at left.

Guidance for representation of emission rates also is provided by EPA; some guidance recommends modeling short-term emission rates so as to protect PSD short-term increments. In historical modeling protocols, short-term emission rates corresponding to the averaging periods of short-term increments were used.

Short-term rates often were expected peak rates, which may have had merit when sources generally, rather than seldom, simultaneously emit at such rates. (For example, see Appendix G.) But, the use of short-term rates conflicts with the definition for actual emissions in PSD rules. Because short-term rates are larger than rates as actual emissions during operating hours, use of short-term rates 24/7/52 would have resulted in ratios larger than shown in the table above.

5.4 Future accuracy tests ⁵

Future accuracy tests of model predicted 24-hour sulfur dioxide concentrations will be completed using CALMET and CALPUFF control file inputs as provided in this protocol, meteorological data for years 2000 and 2001, current-period sulfur dioxide emission rates as provided in this protocol and the highest 25 daily averages of ambient monitoring data for both years. (See Appendix H.) The model predicted concentrations for these accuracy tests will be obtained at model receptors representing locations of monitors, and such receptors can be added to the list of Class I area receptors. Thus, no special modeling for accuracy tests is necessary.

Accuracy tests of model predicted 3-hour sulfur dioxide concentrations will be conducted in the same manner, but using the highest 3-hour averages of ambient monitoring data.

⁵ No model performance tests, such as the execution efficiency of model software, are included in this alternate modeling protocol.

6.0 Deterioration of ambient sulfur dioxide in PSD Class I areas.

6.1 Model receptors

In air quality modeling, receptors are geographic points where the model predicts ambient sulfur dioxide concentrations due to source emitted sulfur dioxide. An attached map shows a two-kilometer Cartesian grid of receptors for each of three (3) PSD Class I areas in North Dakota. Additional receptors have been placed at the perimeter of two of the areas; these receptors are numbered 1xx. A fourth Class I area in North Dakota is small, and only one receptor is placed there. The attached map shows receptors at the southeast perimeter of two Class I areas in northeastern Montana. Alternative modeling will use these Class I area receptor locations.

6.2 Calculating and tabulating deterioration

Air quality deterioration subsequent to the PSD baseline is allowed by the CAA. The amounts of acceptable deterioration for sulfur dioxide were established as PSD primary and alternate increments. The benchmark, or reference point, for gauging deterioration (or improvement) of air quality in PSD Class I areas is the baseline concentration, which is defined in the CAA and PSD rules.

Under EPA's current method of gauging deterioration with the output of modeling source emission rate changes (increases or decreases) after PSD baseline, a baseline concentration is not determined for each short-term increment averaging period (3-hour or 24-hour). A consequence is an undetermined baseline concentration for each averaging period throughout the year at each receptor. And, reports then labeled the tabulated data as the "highest" and the "highest second-highest" (implied as concentration rather than the change in concentration) without acknowledging that the baseline concentration had not been determined.

Furthermore, this method of gauging deterioration lacks technical footing, because models have poor skill in predicting concentrations paired in time with monitored concentrations. For example, ". . . the models are reasonably reliable in estimating the magnitude of highest concentrations occurring sometime, somewhere within an area. . . . However, estimates of concentrations that occur at a specific time and site are poorly correlated with actually observed concentrations . . ." (See paragraph b, section 10.1.2 of 40 CFR 51, Appendix W.) This accuracy scenario is applicable to the current period and the PSD baseline model predicted [estimated] concentrations.

In the future, these problems of EPA's current method will be corrected by using the CALPUFF model to predict hourly ambient sulfur dioxide concentrations (1) at PSD baseline due to a baseline inventory of emitted sulfur dioxide and (2) preceding the date of concern due to a current-period inventory of emitted sulfur dioxide. This procedure also:

- a. recognizes that the model's plume depletion chemistry is not linear,
- b. provides total concentrations due to all emitted sulfur dioxide within the modeling domain that can be used by FLMs to assess exposures to sulfur dioxide by AQRVs and, thus, impacts on AQRVs, and
- c. allows accuracy testing between the model's predicted concentrations and ambient monitoring data.

EPA's current method for gauging sulfur dioxide deterioration at a receptor will be emulated with output from the modeling of each of the two sulfur dioxide emissions inventories. The procedure that follows improves on the EPA's current method, but it still assumes that the model has skill in predicting concentrations paired in time with monitored concentrations. It begins by using the same meteorological year(s) when modeling each inventory.

- Step 1. The model-predicted hourly concentrations due to each emissions inventory are averaged for each sequential 24-hour time block (day) throughout the year. The 24-hour time block correspond to the PSD 24-hour increment averaging period.
- Step 2. For each receptor, the block 1 (i.e., first day of year) concentration due to baseline emissions is subtracted from the block 1 concentration due to current-period emissions. This is the paired in space and time (S & T) approach. If the difference (ΔX) is larger than the applicable PSD increment, an increment exceedance occurs. The subtraction is repeated for the remaining 364 24-hour time blocks. Conceptually, multiple exceedances are possible at the receptor.
- Step 3. The highest second highest difference (HSH ΔX) throughout the year among all receptors is extracted from the ΔX data pool created with Step 2.
- Step 4. Results of Steps 1 through 3 will be tabulated and labeled as shown in the table below.
- Step 5. Steps 1 through 4 are repeated for each modeled meteorological year.

Monitoring data cannot be used to replicate EPA's current method of gauging deterioration with the output of modeling. (See Appendix H.) Alternate procedures for gauging sulfur dioxide deterioration establish a baseline concentration due to baseline emissions of sulfur dioxide as a single value throughout the year (1) for each receptor or (2) for the Class I area. These procedures are consistent with the CAA, PSD rules, EPA regulations and model accuracy.

The first alternate procedure for gauging deterioration will be implemented by replacing Step 2 above as follows. This procedure does not assume that the model has skill in predicting concentrations paired in time with monitored concentrations.

- Step 2a. For each receptor, determine the model-predicted baseline concentration as the second-highest of the 365 24-hour block-averaged sulfur dioxide concentrations throughout the year due to baseline emissions of sulfur dioxide.

Step 2b. For each receptor, compute deterioration by subtracting its baseline concentration (a single value from Step 2a) from each of the 365 model-predicted block-averaged sulfur dioxide concentrations throughout the year due to current period emissions of sulfur dioxide. This is the paired in space (S) only approach. Differences (ΔX) larger than the applicable PSD increment are exceedances; conceptually, multiple exceedances are possible at the receptor.

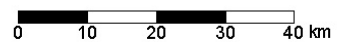
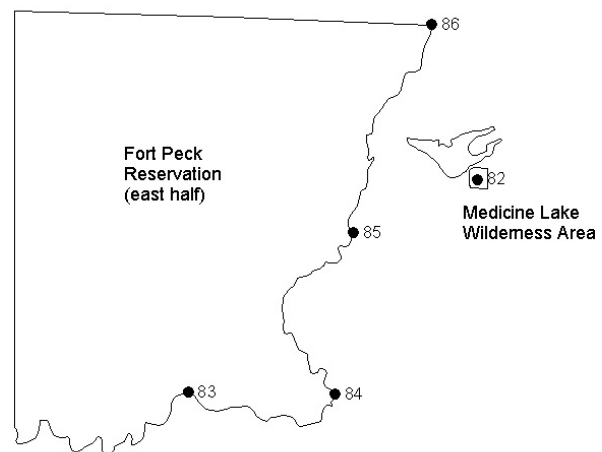
CALMET-CALPUFF predicted 24-hour sulfur dioxide deterioration for _____, a PSD Class I area.					
Source scenario: with _____ or without _____ sources granted certifications of no adverse impact by a FLM.					
Deterioration gaging method: paired in S&T _____ or paired in S only _____. When deterioration (ΔX) is 5.0 ug/m3 or larger, an increment exceedance occurs.	Meteorological Data _____				
	Year 1	Year 2	Year 3	Year 4	Year 5
Total receptors in Class I area.					
----- Number of receptors with at least one exceedance.					
----- Number of receptors with two or more exceedances, because one is allowed at each receptor.					
Highest second-highest ΔX among all receptors. (When no receptor has two or more exceedances, this number is less than 5.0 ug/m3.)					
----- Corresponding current concentration (ug/m3).					
----- Corresponding baseline concentration (ug/m3).					

When the highest of the modeled predicted HSH ΔX concentrations among the modeled meteorological years is less than the increment, no second exceedance of that increment for that Class I area occurred. All procedural steps will be repeated for each PSD Class I area.

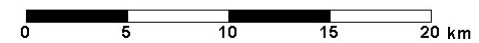
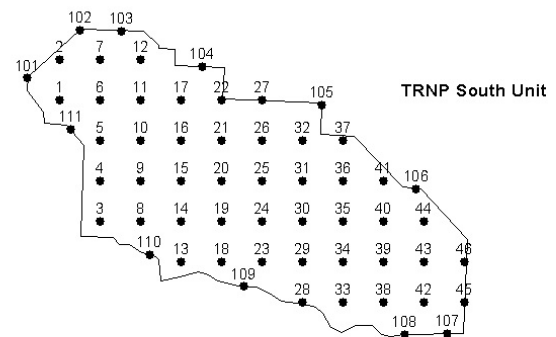
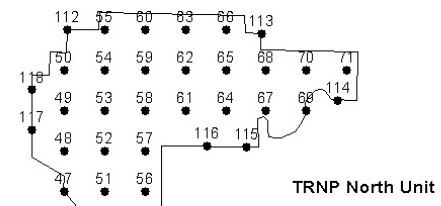
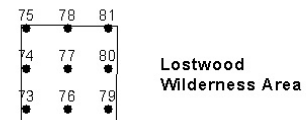
Finally, deterioration during the 2,920 consecutive 3-hour averaging periods throughout the year and exceedances of the PSD 3-hour sulfur dioxide increment of 25 ug/m3 will be tabulated for each meteorological year and PSD Class I area in the same manner.

Final.

Receptor Locations - Montana Class I Areas



Receptor Locations - North Dakota Class I Areas



7.0 Summary.

The proposed alternate modeling protocol provides tabulated results of predicted deterioration of short-term sulfur dioxide concentrations under:

- 1) one meteorological input scenario – RUC2^d data with three years (2000, 2001 and 2002) of assimilated NWS twice-daily upper air and hourly surface meteorological data,
- 2) two current-period emissions input scenarios – one scenario with and the other without the two sources granted FLM certifications of no adverse impact, and
- 3) two scenarios of tabulation of predicted concentrations due to baseline emissions and due to current emissions – one with concentrations paired in time throughout the year at each receptor and the other with concentrations unpaired in time at each receptor.

The ARPS Data Assimilation System (ADAS) was used to 1) assimilate hourly surface weather data and terrain data with NOAA's Rapid Update Cycle version 2 (RUC-2) short-term forecast model data and 2) extrapolate these data to a 10 kilometer horizontal resolution. The assimilated and extrapolated data were compiled in a format compatible with the MM5 data ingest capability of CALMET. For this protocol, the resulting data are labeled RUC2^d. Tests of the correspondence between RUC2^d data and NWS data at low elevations (e.g., between 10 meters and 100 meters above ground) and at low wind speeds (e.g., less than 5 meters per second) may be completed, although the results of some tests are available.

Neither prior modeling protocols nor the proposed alternate protocol provide absolute results, because the science of the models and many data inputs for models are applications of known, but less than perfect, information. The data results of modeling air quality typically have been presented as numbers without uncertainty qualifiers. Accuracy testing captures the combined uncertainties of the science in the model and the inputs to the model.

The proposed alternate modeling protocol contains a provision for testing the accuracy of model predicted concentrations; such testing entails quantifying correspondence between model predicted concentrations and monitoring data. Model predicted concentrations resulting from modeling current sulfur dioxide actual emissions and meteorological inputs will be used, and actual sulfur dioxide observations obtained during the same time lines will be used.

Monitoring of ambient concentrations is a measured consequence of all emitted sulfur dioxide in and surrounding the modeling domain at monitor locations, including any deterioration since PSD baseline more than 23 years earlier. The Department of Health has monitors in the North and South Units of the TRNP. For example, the second highest 24-hour monitored concentrations in the South Unit of TRNP were: for year 2000, 9.39 ug/m³; 2001, 8.81 ug/m³; and 2002, 8.30 ug/m³.

Inventories of emitted sulfur dioxide were assembled for PSD baseline and for a current period. The sum of rates of emitted sulfur dioxide for sources at PSD baseline is estimated as 29,683.9 pounds per hour (reflecting 24/7 application by the model), and the sum for sources at current period is 43,658.2 pounds per hour. The sum of rates during PSD baseline is 0.678 (67.8 percent) of the sum of current rates. These sums do not include the numerous oil and gas production sources; there were about 300 fewer of these sources during year 2000 compared to 1977-78. A crude estimate of the baseline concentration at the location of the monitor in the South Unit of TRNP is the multiplication product of the emissions ratio of 0.678 and the second highest monitored concentration for each year of monitoring data. Thus, the crude estimates of baseline concentrations are: from data for year 2000, 6.37 ug/m³; 2001, 5.97 ug/m³; and 2002, 5.63 ug/m³.

The challenge is to achieve a modeling protocol that applies the models, science and engineering judgement so as to meaningfully predict current and PSD baseline actual ambient concentrations.

Appendix A – CALMET code revision

Subroutine DIAGNO in CALMET was changed ⁶

from:

```
52 IF(ICALC.LT.0) GO TO 850
C
C EXTRAPOLATE SURFACE WINDS
C EXTRAPOLATION OPTIONS:
C 1) IF IABS(IEXTRP)=1, THEN DO NOT EXTRAPOLATE FROM SURFACE DATA
C 2) IF IABS(IEXTRP)=2, THEN USE POWER LAW
C 3) IF IABS(IEXTRP)=3, THEN USE FEXTRP MULTIPLIER
C 4) IF IEXTRP=4, THEN USE SIMILARITY THEORY
C 5) IF IEXTRP<=0, THEN DO NOT USE LEVEL 1 DATA FROM UA WINDS
C
IF(IABS(IEXTRP).EQ.1) GO TO 91
```

to:

```
52 IF(ICALC.LT.0) GO TO 850
C
C EXTRAPOLATE SURFACE WINDS
C EXTRAPOLATION OPTIONS:
C 1) IF IABS(IEXTRP)=1, THEN DO NOT EXTRAPOLATE FROM SURFACE DATA
C 2) IF IABS(IEXTRP)=2, THEN USE POWER LAW
C 3) IF IABS(IEXTRP)=3, THEN USE FEXTRP MULTIPLIER
C 4) IF IEXTRP=4, THEN USE SIMILARITY THEORY
C 5) IF IEXTRP<=0, THEN DO NOT USE LEVEL 1 DATA FROM UA WINDS
C
GO TO 91
```

⁶ The software change applies only to application of CALMET on State modeling problems and only when using NWS hourly surface and twice-daily upper air data without prognostic meteorological model data, and it may not be universally applicable in other circumstances.

Appendix B – Model accuracy conundrum

The numeric magnitude(s) of the background concentration(s) of sulfur dioxide can impact results of model accuracy tests. More specifically, the amount of over or under prediction bias in model predicted concentrations depends on the value(s) of the background concentration(s). (See section 10.1.3 of 40 CFR Part 51, Appendix W). Over or under prediction bias does not drop out in calculation of air quality deterioration or improvement as demonstrated below.

change (Δ) in actual air quality (AAQ) from baseline (b) to current period (cp)

$$\Delta\text{AAQ} = \text{AAQ}_{\text{cp}} - \text{AAQ}_{\text{b}}$$

modeling bias (β) with units of percent is $[R - 1.0] * 100$.

$$R = (\text{MAQ} + \text{BC}) / \text{AAQ}$$

$$\text{AAQ} = (\text{MAQ} + \text{BC}) / R$$

where:

MAQ = modeled air quality

BC = background concentration

with substitution, the change in air quality becomes

$$\Delta\text{AAQ} = [(\text{MAQ} + \text{BC}) / R]_{\text{cp}} - [(\text{MAQ} + \text{BC}) / R]_{\text{b}}$$

when the ratio R is the same for a wide range of concentrations, the change in air quality becomes

$$\Delta\text{AAQ} = [(\text{MAQ} + \text{BC})_{\text{cp}} - (\text{MAQ} + \text{BC})_{\text{b}}] / R$$

when the background concentrations at cp and b are the same, the change in air quality becomes

$$\Delta\text{AAQ} = [\text{MAQ}_{\text{cp}} - \text{MAQ}_{\text{b}}] / R$$

In summary, the accuracy of model predicted concentrations is dependant upon the background concentration, and changes in concentrations are dependent on model accuracy.

If a model is used to assess attainment of a PSD increment, it follows that the model can also be used to test strategies for emission reductions when attainment is not demonstrated. While modest over prediction is desirable so as to protect the PSD increment, significant over prediction can have significant implications for such strategies.

Appendix C – Dates of source permits, startup and shutdown.

Plant	Owner or Operator	Date Permit Ap Rec'd	Date Ap Complete	PTC or PTO Date	Date of Startup	Operating
Sources constructed after the PSD minor source baseline date and operating during current period						
Northern Gas	Northern Gas Products	Sep-83	Feb-84	Feb-85	never built	no
Nokota Methanol	Nokota Company	Feb-80	Jun-81	Jan-83 *	never built	no
Whitetail Gas	Amoco	Jul-80	Sep-80	Jan-83 *	never built	no
AVS U-3	Basin Electric Coop.	Jan-78	May-80	Jan-83 *	never built	no
Grasslands Gas	Bear Paw	Oct-79	unknown	Oct-80	Apr-80	yes
Stanton U-10 **	Great River Energy	Dec-77	unknown	May-79	Jul-82	yes
AVS U-1	Basin Electric Coop.	Mar-77	Jan-78 #	Feb-78	May-83	yes
AVS U-2	Basin Electric Coop.	Mar-77	Jan-78 #	Feb-78	Oct-85	yes
Coyote	Ottertail Power	Oct-76	unknown	Aug-77	Mar-81	yes
Great Plains Synfuels	Great Plain Gasification Co.	Sep-75	unknown	Jan-78 *	Mar-84	yes
Little Knife Gas	Petro Hunt	Oct-77	19-Dec-77 #	Feb-78 *	Jul-78	yes
Coal Creek U-2	Great River Energy	Sep-74	Nov-74 #	Apr-75	Jul-80	yes
Coal Creek U-1	Great River Energy	Sep-74	Nov-74 #	Apr-75	May-79	yes
# date last information received from permit applicant * certifications of no adverse impact granted by a FLM						
** U-1 and U-10 emissions netting based upon historical U-1 emissions to avoid PSD 24-hour increment impact for sulfur dioxide						

Sources constructed after PSD baseline and retired before current period

Temple Gas	Amerada Hess	Feb-84	na	Oct-84	unk-85	shutdown, Aug-96
Teddy Roosevelt	Western Gas Processors	Mar-79	na	Jul-79	Nov-80	shutdown, Jul-93
Perry Petrolane	Perry Processing Co.	unknown	na	Dec-77	unknown	shutdown, abt-92
Shell-Oil Gas	Shell Oil	Jun-79	na	Nov-77	Jul-79	shutdown, abt-92
Boxcar Butte	Kerr McGee	Sep-75	na	Nov-75 *	unk-76 *	shutdown, unk-87
Trenton Gas	Phillips Petroleum	Sep-80	na	Oct-82	unk-81	shutdown, unk-87

Plant	Owner or Operator	Date Permit Ap Rec'd	Date Ap Complete	PTC or PTO Date	Date of Startup	Operating
Killdeer Gas	Koch Hydrocarbon	_____	na	_____	unk-80	shutdown, unk-85

* A PTC for an expansion making the plant a major source was issued May 1976. Startup of the expansion began March 1977.

Sources operating at PSD baseline and continuing to operate during current period

Lignite Gas	Oxy NGL, Inc.	_____	na	_____	unk-61	yes
BP Amoco Oil Refinery	BP Amoco Oil	_____	na	_____	unk-54	yes
Tioga Gas	Amerada Hess	_____	na	_____	unk-54	yes
M.R. Young U-2	Minnkota Power Coop.	Sep-73	na	Jun-74	Mar-77	yes
M.R. Young U-1	Minnkota Power Coop.	Apr-73	na	Jun-73	Oct-70	yes
Stanton U-1	Great River Energy	Mar-73	na	Jun-73	unk-67	yes
Leland Olds U-2	Basin Electric Coop.	Mar-73	na	Jun-73	Nov-75	yes
Leland Olds U-1	Basin Electric Coop.	Mar-73	na	Jun-73	unk-66	yes
Heskett U-2	Montana Dakota Utilities	Apr-73	na	Jun-73	unk-63	yes
Heskett U-1	Montana Dakota Utilities	Apr-73	na	Jun-73	unk-54	yes

Sources operating at PSD baseline and subsequently retired

Royal Oak	Royal Oak, Inc.	_____	na	_____	bfr 1959	shutdown, unk-90
Neal Station	Basin Electric Coop.	Apr-73	na	_____	unk-52	shutdown, unk-85
Flying J Refinery	Flying J, Inc.	_____	na	_____	abt 1954	shutdown, unk-83
Beulah Station	Montana Dakota Utilities	_____	na	_____	1927	shutdown, unk-86

na = not applicable bfr = before unk = unknown abt = about

Appendix D – Baseline source normal operations and related source operating data.

Generally, normal source operation, a term within the rule definition for actual emissions, is the two-year period preceding and ending with the PSD minor source baseline date. An EPA interpretive regulation, i.e., the preamble to the 1980 update of PSD rules, indicates that a reviewing authority has discretion to use another two-year period when that period is more typical of a source's normal operation.

Power plants

An indicator of annual power plant operating activity is the amount of net power generation, as kilowatt hours, by the power plants. These data are available for units of power plants from the State's Tax Department for years 1990 and later; the data can be reduced to net generation per operating hour. An alternate indicator of activity is the annual utilization of a combustion system of power plants. Annual utilization is a ratio computed as the annual average hourly heat input divided by the boiler's rated heat-input capacity. The annual average hourly heat input during system operation is the annual total heat content of coal burned during operation divided by the annual total hours of operation. The rates of net generation per operating hour and annual utilization of boiler heat-input capacity correlate, indicating that utilization of boiler heat-input capacity is a viable indicator of normal source operation.

Data for computation of the utilization of the rated heat-input capacity of each coal-fired combustion system of power plants for each year from 1975 through 1982 are provided in the attached tables. The data are provided for power production sources that operated during both baseline and current periods. In addition, the average utilization of operating systems (units) within respective power plants, except GRE Stanton, also is provided for these years. Finally, the two consecutive years during which the greatest use of heat-input capacity of the plant's systems are delineated in the attached tables. The data revealed that combustion system operations following the PSD baseline date were more representative of normal source operations for some power production sources.

More representative normal operations for individual units of power plants were not considered. In addition, start-up operating problems were not considered. For example, Unit 2 of the Leland Olds plant had start-up problems that extended into year 1976, and Unit 2 of the M.R. Young plant had start-up problems during year 1978.

The annual average coal sulfur content for each year from 1975 through 1982 is also provided in attached tables. The data illustrate significant year to year variation in annual average sulfur content of the lignite coal. The coal sulfur content data were not used or considered in selecting the two consecutive years of normal source operations. The coal sulfur content for the two years of normal source operation were used in computing baseline sulfur dioxide emission rates.

Royal Oak plant

The Royal Oak plant was a charcoal briquette production plant; the plant ceased briquette production and shut down during 1990. Three spreader stoker boilers converted local lignite coal to process steam and heat for plant operations during colder season; fewer boilers were operated during warmer seasons. Two Lurgi carbonizer units provided char for briquettes.

During 1975 and 1976, the plant anticipated briquette production increases and began expansion of char production by adding two Herreschoff carbonizer furnaces. These furnaces began operation during 1976 and 1978; addition of these furnaces was a major modification to the plant. The Herreschoff furnaces operated until the plant was shut down. The sulfur dioxide emitted by these furnaces was not included in PSD baseline sulfur dioxide emissions for the Royal Oak plant.

Annual emission inventory reports from 1974 provide data on coal usage, the annual average sulfur content of that coal and the annual hours of operation of the boilers and carbonizers. These data indicated that coal usage increase dramatically during years 1978 and 1979. Because coal usage is an indicator of utilization of plant production capacity, years 1978 and 1979 are more representative of normal operations anticipated by the plant at that time.

The PSD baseline sulfur dioxide emission rate for the three boilers for 1978 and 1979 is based upon annual coal usage, the annual hours of operation of these boilers, the annual average sulfur content of that coal and a sulfur dioxide emission factor of 30S.

The baseline sulfur dioxide emission rate for the two Lurgi carbonizing furnaces is based upon coal usage of 480 tons per day (maximum operating capacity) and 10 percent down time, as no reliability (availability) data are available. Sulfur dioxide emission data from stack testing in late 1984 were used to establish an emission factor of 29.6S, because no other valid performance data were available. The annual average sulfur content of coal used during years 1978 and 1979 were used to complete the emission rate calculations.

Source locations and stack operating data

Source locations and stack operating data for all sources, except oil and gas production sources, in operation at PSD baseline and during the current period are provided in two attached tables. The longitude and latitude coordinates of several sources have been verified and updated. The coordinates are accurate to about 15 meters or less where emission point sources had been surveyed.

Operating Data for Select Units of Baseline Power Plants *												
Heskett												
Unit 1						Unit 2						Units 1 & 2
	Hours of	Coal Fired	Total Heat	Boiler ¹	Ave. S		Hours of	Coal Fired	Total Heat	Boiler ²	Ave. S	
Year	Operation	(tons)	(Btu)	Utilization	(% by wt)		Operation	(tons)	(Btu)	Utilization	(% by wt)	Ave. Boile
1975	7,562	146,608	2.06E+12	0.703	0.66		5,690	281,196	3.95E+12	0.757	0.66	0.730
1976	7,433	159,196	2.23E+12	0.774	0.75		7,668	376,017	5.60E+12	0.797	0.75	0.786
1977	7,879	171,162	2.38E+12	0.781	0.68		7,871	406,145	5.65E+12	0.784	0.68	0.783
1978	7,920	161,755	2.25E+12	0.734	0.71		7,388	342,560	4.77E+12	0.704	0.71	0.719
1979	7,940	150,922	2.11E+12	0.685	0.67		7,402	330,743	4.62E+12	0.681	0.67	0.683
1980	7,776	160,912	2.28E+12	0.758	0.75		7,739	361,847	5.13E+12	0.723	0.75	0.741
1981	7,598	153,335	2.16E+12	0.733	0.80		7,765	358,830	5.04E+12	0.709	0.80	0.721
1982	8,004	142,409	1.97E+12	0.637	0.78		7,862	335,436	4.65E+12	0.645	0.78	0.641
Footnote 1 -- rated boiler capacity for Unit 1 is 387 mBtu per hour						Footnote 2 -- rated boiler capacity for Unit 2 is 916 mBtu per hour						
Leland Olds												
Unit 1						Unit 2						Units 1 & 2
	Hours of	Coal Fired	Total Heat	Boiler ³	Ave. S		Hours of	Coal Fired	Total Heat	Boiler ⁴	Ave. S	
Year	Operation	(tons)	(Btu)	Utilization	(% by wt)		Operation	(tons)	(Btu)	Utilization	(% by wt)	Ave. Boiler
1975	8,254	1,335,704	1.72E+13	0.793	0.50		1,173	238,726	3.07E+12	0.510	0.53	0.652
1976	7,553	1,255,995	1.65E+13	0.833	0.45		6,776	1,958,680	2.57E+13	0.740	0.45	0.787
1977	7,894	1,306,785	1.73E+13	0.835	0.44		6,667	1,964,660	2.60E+13	0.760	0.44	0.798
1978	8,502	1,361,539	1.83E+13	0.819	0.74		7,445	2,435,160	3.26E+13	0.855	0.74	0.837
1979	8,232	1,127,701	1.50E+13	0.695	0.65		8,064	2,301,417	3.60E+13	0.870	0.65	0.783
1980	8,232	1,165,082	1.56E+13	0.721	0.85		8,064	2,098,218	2.80E+13	0.677	0.85	0.699
1981	8,102	1,104,774	1.48E+13	0.696	0.50		7,028	2,088,491	2.79E+13	0.775	0.50	0.736
1982	6,718	866,848	1.16E+13	0.659	0.54		7,269	2,099,524	2.81E+13	0.753	0.54	0.706
Footnote 3 -- rated boiler capacity for Unit 1 is 2,622 mBtu per hour						Footnote 4 -- rated boiler capacity for Unit 1 is 5,130 mBtu per hour						
Ave. S = annual average coal sulfur content in units of percent by weight.												
* Data sources are annual emissions inventory reports.												

Operating Data for Select Units of Baseline Power Plants *											
M.R. Young											
Unit 1						Unit 2					Units 1 & 2
	Hours of Operation	Coal Fired (tons)	Total Heat (Btu)	Boiler ¹ Utilization	Ave. S (% by wt)	Hours of Operation	Coal Fired (tons)	Total Heat (Btu)	Boiler ² Utilization	Ave. S (% by wt)	Ave. Boile Utilization
1975	7,773	1,470,000	1.93E+13	0.776	0.64						
1976	8,188	1,581,000	2.01E+13	0.768	0.52						
1977	8,003	1,527,511	1.98E+13	0.773	0.63						
1978	6,714	1,427,485	1.84E+13	0.854	0.65	6,890	1,956,191	2.51E+13	0.579	0.65	0.717
1979	7,870	1,508,182	2.03E+13	0.807	0.65	8,064	2,508,465	3.38E+13	0.665	0.65	0.736
1980	7,858	1,454,708	1.92E+13	0.762	0.71	7,571	2,410,163	3.01E+13	0.631	0.71	0.697
1981	7,456	1,363,573	1.78E+13	0.747	0.54	7,346	2,067,550	2.70E+13	0.584	0.54	0.666
1982	6,538	1,146,705	1.50E+13	0.716	0.63	7,106	1,808,847	2.39E+13	0.340	0.63	0.528
Footnote 1 – rated boiler capacity for Unit 1 is 3,200 mBtu per hour						Footnote 2 – rated boiler capacity for Unit 1 is 6,300 mBtu per hour					
GRE Stanton											
Unit 1											Unit 1 only
	Hours of Operation	Coal Fired (tons)	Total Heat (Btu)	Boiler ³ Utilization	Ave. S (% by wt)						Ave. Boiler Utilization
1975	7,896	683,609	9.47E+12	0.666	0.74						0.666
1976	7,272	746,205	1.04E+13	0.794	0.65	Unit 10 is not a PSD baseline source					0.794
1977	7,700	737,106	1.01E+13	0.725	0.64						0.725
1978	5,466	577,004	8.05E+12	0.818	0.61						0.818
1979	7,205	728,136	1.01E+13	0.781	0.63						0.781
1980	8,250	845,822	1.19E+13	0.799	0.64						0.799
1981	8,150	816,624	1.12E+13	0.766	0.59						0.766
1982	7,211	739,001	1.02E+13	0.782	0.65						0.782
Footnote 3 – rated boiler capacity for Unit 1 is 1,800 mBtu per hour											
Ave. S = annual average coal sulfur content in units of percent by weight.											
* Data sources are annual emissions inventory reports.											

PSD baseline-period source locations and stack operating data.									
					Stack	Base	Stack	Exit	Exit
		Longitude	Latitude		height	elevation	diameter	velocity	temp.
Source	Unit	(degrees)	(degrees)		(m)	(m)	(m)	(m/s)	(deg. K)
Beulah Power Plant	1 & 2	-101.77088	47.26346		23.0	567.0	1.7	7.6	477.0
	3, 4 & 5	-101.77088	47.26346		30.5	567.0	2.1	14.6	527.0
Neal Station	1 & 2	-100.88236	48.02377		42.4	488.0	1.8	25.0	470.0
Royal Oak Briquetting Plant	Boilers 1, 2 & 3	-102.70032	46.85862		19.2	751.0	1.4	9.8	520.0
	Carbonizer Furnaces	-102.69941	46.86010		26.2	751.0	3.4	9.4	1,172.0
Williston Refinery	Heaters + boiler 2	-103.58690	48.14555		17.3	575.0	0.9	3.2	700.0
	Boiler 1	-103.58690	48.14555		30.2	575.0	1.2	3.4	464.0
	Boiler 3	-103.58690	48.14555		9.1	575.0	0.8	6.3	464.0
R.M. Heskett Station	1	-100.88383	46.86719		91.4	514.8	2.2	20.7	461.7
	2	-100.88350	46.86641		91.4	514.8	3.7	17.4	419.7
Leland Olds Station	1	-101.32125	47.28140		106.7	518.3	5.3	19.7	450.0
	2	-101.31991	47.28080		152.4	518.3	6.7	25.0	448.6
MR. Young Station	1	-101.21445	47.06700		91.4	597.4	5.8	18.5	449.1
	2	-101.21470	47.06625		167.6	597.4	7.6	19.2	361.8
Stanton Station	1	-101.33205	47.28650		77.7	518.3	4.6	19.9	411.1
Tioga Gas Plant	SRU Incinerator	-102.91625	48.39835		30.5	686.0	1.7	7.7	782.0
Lignite Gas Plant	SRU Incinerator	-102.54183	48.87317		38.1	598.0	0.4	19.9	893.0
Mandan Refinery	Boilers 1, 2 & 3	100.87838	46.85124		31.8	518.3	1.7	12.5	424.7
	FCU + Crude Furnace	-100.88038	46.85198		60.7	518.3	3.4	9.9	547.0
	Alkylation Unit	-100.87780	46.85614		53.0	518.3	2.0	6.1	447.0
	Ultraformer Furnaces	-100.87783	46.85328		29.1	518.3	1.3	5.9	530.8

PSD current-period source locations and stack operating data.								
				Stack	Base	Stack	Exit	Exit
		Longitude	Latitude	height	elevation	diameter	velocity	temp.
Source	Unit	(degrees)	(degrees)	(m)	(m)	(m)	(m/s)	(deg. K)
R.M. Heskett Station	1	-100.88383	46.86719	91.4	514.8	2.2	20.7	461.7
	2	-100.88350	46.86641	91.4	514.8	3.7	17.4	419.7
Leland Olds Station	1	-101.32125	47.28140	106.7	518.3	5.3	19.7	450.0
	2	-101.31991	47.28080	152.4	518.3	6.7	25.0	448.6
M.R. Young Station	1	-101.21445	47.06700	91.4	597.4	5.8	18.5	449.1
	2	-101.21470	47.06625	167.6	597.4	7.6	19.2	361.8
Stanton Station	1 & 10	-101.33205	47.28650	77.7	518.3	4.6	19.9	411.1
Tioga Gas Plant	SRU Incinerator	-102.91625	48.39835	50.3	686.0	0.9	7.7	782.0
Mandan Refinery	Boilers 1, 2 & 3	100.87838	46.85124	31.8	518.3	1.7	12.5	424.7
	FCCU + Crude Furnace	-100.88038	46.85198	60.7	518.3	3.4	9.9	547.0
	Alkylation Unit	-100.87780	46.85614	53.0	518.3	2.0	6.1	447.0
	Ultraformer Furnaces	-100.87783	46.85328	29.1	518.3	1.3	5.9	530.8
	SRU Incinerator	-100.87766	46.85201	60.8	518.3	0.6	5.7	589.0
Coal Creek Station	1	-101.15782	47.37854	201.0	602.0	6.7	25.9	358.5
	2	-101.15642	47.37858	201.0	602.0	6.7	24.9	354.5
Antelop Valley Station	1	-101.83534	47.37004	182.9	588.3	7.0	19.0	358.2
	2	-101.83556	47.37096	182.9	588.3	7.0	19.1	356.7
Coyote Station	1	-101.81480	47.22105	152.0	556.9	6.4	25.4	370.7
Little Knife Gas Plant	SRU Incinerator	-103.09806	47.29667	59.5	780.5	1.8	1.5	744.7
Great Plains Synfuels	Main stack	-101.84050	47.36160	119.8	588.3	7.0	12.1	357.1
	Start-up flare	-101.83886	47.36420	68.6	588.3	0.5	98.4	1,000.0
	Main flare	-101.83581	47.35576	76.2	588.3	1.0	100.5	1,000.0
	Back-up flare	-101.83900	47.36370	30.5	588.3	0.5	102.1	1,000.0
PPL Corp Colstrip	3	-106.6239	45.8842	210.9	988.7	7.3	26.9	361.3
	4	-106.6236	45.8842	210.9	988.7	7.3	27.6	362.7
CELP Colstrip		-106.6545	45.9748	61.0	945.1	2.5	22.6	433.2

Appendix E – Source specific sulfur dioxide emission factors.

Factors derived from 2000 and 2001 coal and CEM data.

The sulfur dioxide emission rate for lignite-fired boilers is a function of the amount of coal burned and the sulfur content of that coal, as well as the amount and form of natural sulfur scrubbing agents (e.g., sodium) in that coal, boiler design and boiler load. A current-time emission factor was calculated for units of power plants that do not have a sulfur dioxide emission control system. The factors are a mass-balanced calculation between annual sulfur dioxide emissions from recent continuous emissions monitoring (CEM) system data and corresponding coal consumption and coal sulfur-content data. The coal data were obtained from annual emissions inventory reports. All data are provided in an attached table.

An emission factor cannot exceed 40S, which has math units of pounds SO₂ per ton coal, due to the physical principal of conservation of mass, unless error occurred in coal or CEM data. S is the coal sulfur content in percent.⁷ The calculated emission factor for Unit 2 of the Leland Olds plant is 40.7S, as shown on the attached table. The cause(s) for this factor could be error in tons of coal burned or a positive bias in CEM data and/or a negative bias in coal sulfur-content data.⁸ CEM emissions data are derived from two CEM system monitoring components; sulfur dioxide concentrations in the stack air stream and the speed of that air stream.

A study of sulfur dioxide emissions was completed by sampling lignite-fired boilers; the sampling occurred during years 1970 through 1972. (See Gronhovd, G.H., et.al., May 1973. Some Studies on Stack Emissions from Lignite-Fired Power Plants. Lignite Symposium, May 9-10, 1973, Grand Forks, North Dakota.) Emission factors from sampling results (per data in table 3, Gronhovd, et.al.) for Unit 1 of the Leland Olds power plant and Unit 1 of the M.R. Young power plant also are provided in the attached table.

⁷ The average amount of sulfur dioxide produced during an hour of combustion is equal to 40S times the coal consumed during the year divided by the number of operating hours during the year. When no sulfur is retained in combustion slag or ash, all sulfur in coal exits into ambient air through the stack. Emission factors less than 40S occur when some sulfur is retained.

⁸ Assuming that the quantity of coal which was fired is accurate and that quality CEM system data have a positive bias of 3 percent or less (<http://www.epa.gov/ttn/chief/ap42/ch01/bgdocs/b01s07.pdf>; Chapters 3 and 4), then an emission factor larger than 40S suggests that the average coal sulfur content was under reported or that the laboratory technique for extraction of sulfur from coal does not extract all sulfur.

EPA reviewed and relied on data provided by Gronhovd, et.al., when developing a sulfur dioxide emission factor for combustion of lignite. (<http://www.epa.gov/ttn/chief/ap42/ch01/bgddocs/b01s07.pdf>) When sodium oxide in ash ranges between 2 and 8 percent, sulfur oxide emission factors range from 23.1S to 40.0S. The second highest was 37.4S, and the average was 32.3S. (Id., Table 4-1.)

Larger emission factors are conservative. Consider a scenario where CEM data are not available, such as years prior to 1995. Following AP-42, the source emitted sulfur dioxide is equivalent to the multiplication product of variables K, S and C, where K is a constant and ranges from 23.1 to 40.0, S is the average coal sulfur content in percent and C is the annual tons of coal fired in a combustion system. When K is the same for both current and PSD baseline periods, the difference in emitted sulfur dioxide is K times $[(SC)_{cp} - (SC)_{bp}]$ where cp represents current period and bp represents baseline period. Clearly, as K increases to 40, the difference in emitted sulfur also increases, because less sulfur dioxide is retained in ash.

One criterion in use of PSD baseline emission factors would allow variation in factors due to variation in combustion system design. (See attached table.) For example, Unit 1 of the Leland Olds power plant is a pulverized wall-fired unit, and Unit 2 is a cyclone unit.

Another criterion in deriving PSD baseline emission factors is that sulfur dioxide emission rates must have an apples-to-apples basis between current emissions and PSD baseline emissions – at minimum at each source. For example, there are no CEM sulfur dioxide emissions data for the baseline period. Do the results of the Gronhovd, et.al., study correspond to the CEM based factors? No basis exists for resolving the question.⁹ Using Unit 1 of the Leland Olds plant as an example, the emission factor of 33.4S calculated from Gronhovd, et.al., data and the factor of 37.4S calculated from current CEM data are within 12 percent of one another. (See attached table.)

At PSD baseline, feed coal for both units of the Leland Olds plant was provided from the Glenharold Mine, which was closed in 1993. After that date, feed coal for both units was obtained from the Freedom Mine; however, after year 2000, feed coal for Unit 2 included other sources. “The SO_x emissions from lignite combustion depend on the sulfur content of the lignite and the lignite composition (viz., sulfur content, heating value, and alkali concentration).” (<http://www.epa.gov/ttn/chief/ap42/ch01/bgddocs/b01s07.pdf>, Chapter 2.) The alkali constituents are sodium, calcium and potassium in reactive form. Since potassium is generally present in lignites in very small amounts, the alkalis most responsible for sulfur dioxide retention in lignite fly ash are sodium and calcium. (See

⁹ Significant advances have occurred in stack sampling methods, including quality control, since 1971. The method used by Gronhovd, et.al., at that time likely would not be used now. Required Relative Accuracy Test Audits of CEM systems are more rigorous. Thus, greater accuracy of CEM data would be expected.

Gronhovd, et.al., page 6.) “The sodium oxide content is believed to have the greatest effect on sulfur conversion . . .” (<http://www.epa.gov/ttn/chief/ap42/ch01/bgdocs/b01s07.pdf> , Chapter 2.)

A second question is: Are the ash constituent concentrations consistent between coals from the Glenharold Mine and the Freedom Mine? Prediction of stack vented sulfur dioxide using ash concentrations for sodium oxide, silicon oxide, calcium oxide and aluminum oxide was illustrated in 1973. (See Gronhovd, G. H., et.al., May 1973. Technology and Use of Lignite. Information Circular 8650, Bureau of Mines, United States Department of the Interior.) Test data obtained at five power plants were used to establish the regression equation for the prediction. (Id., equation 5 on page 93 and figure 59 on page 95.) One of the five power plants was the Leland Olds power plant; only Unit 1 was operational at the time of the plant testing, because Unit 2 was constructed after 1973. Regression equations for prediction of emitted sulfur dioxide for each of the plants, including the Leland Olds plant, were not reported, which is likely due to the limited test data for each individual plant.

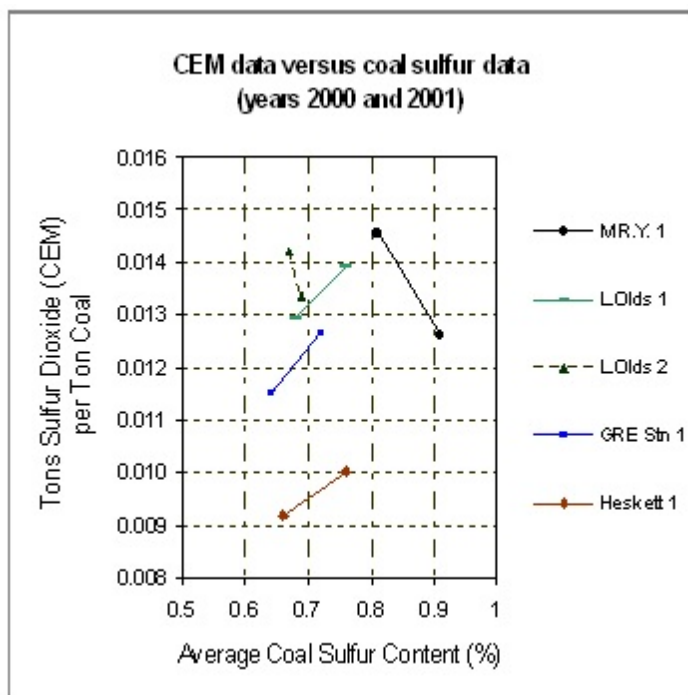
Unit 1 coal fly ash concentrations for sodium oxide, silicon oxide, calcium oxide and aluminum oxide also were reported in 1996. (See Pflughoeft-Hassett, Debra F., April 1996. Survey and Demonstration of Utilization Potential of North Dakota Lignite Ash Resources. Energy & Environmental Research Center, Grand Forks, North Dakota, page 14.) The Unit 1 ash constituent data for coal obtained from the Glenharold Mine and the Freedom Mine are provided in the table at right. The data indicate no apparent significant difference in coal ash concentrations of the four ash constituents between mines.

Ash constituent concentrations (percent by weight) for Unit 1 of the Leland Olds power plant.		
Ash constituent	Glenharold Mine (range of values)	Freedom Mine
sodium oxide	5.1 – 8.8	7.55
silicon oxide	30.7 – 37.5	29.09
calcium oxide	16.2 – 20.2	21.14
aluminum oxide	11.0 – 13.8	13.06

Additional questions are: What might be the explanation for the sulfur dioxide emission factor of 40.7S for Unit 2 of the Leland Olds plant, and what might be alternatives to that factor? (See attached table.) The 40.7S factor provides a baseline emission that is identical to the results of the following calculation sequence. First – calculate an emission factor, EF, for the current time period as the ratio of total emitted sulfur dioxide emissions from CEM data and total coal fired in the combustion system, and second – calculate the multiplication product of EF, the ratio of baseline period average coal sulfur to current period average coal sulfur and total baseline coal fired.

The weighted average sodium oxide content of the lignite ashes for Unit 2 of the Leland Olds plant declined from 3.4 percent during 1977-1978 to 3.0 percent during 2000-2001, which are the baseline-period years and current-period years. The minor decline in

sodium oxide suggests that the sulfur dioxide emission factor for Unit 2 during current time would be modestly larger than the factor during the baseline. [Note. A statistical test of the data, such as the Student's t-test, to determine whether differences in mean sodium oxide content of ashes for the two time periods are significantly different was not completed.]



Rates of sulfur dioxide emission for the state's lignite-fired power plants, that are calculated using EPA's AP-42 method, have an accuracy uncertainty due to coal sulfur-content data and to CEM data. Data in the attached table are plotted on the chart at left. The consistency between the two years of data is shown by the double ratio in the chart at right. Four of the five double ratios at right are within 10 percent of 1.0, which indicates that, year to year, the CEM and coal sulfur data may not be reasonably consistent for Unit 1 of the M.R. Young plant.

$$\frac{Y2000(S_{AVE} / (T_{SO2}/T_{COAL}))}{Y2001(S_{AVE} / (T_{SO2}/T_{COAL}))}$$

M.R.Y. 1	1.298
L. Olds 1	0.963
L. Olds 2	1.097
GRE Stn 1	0.940
Heskett 1	0.948

Initially, CEM system measured stack air stream speeds were biased high. EPA corrected CEM system calibration methods in 1999, and EPA has reviewed the CEM data from state sources and found it of adequate quality. (<http://www.epa.gov/ttn/chief/ap42/ch01/bgdocs/b01s07.pdf>, Chapters 3 and 4.)

The sulfur and oxide constituents in the state's lignite coal are highly variable; thus, annual averages of sulfur for years 2000 and 2001 as in emissions inventory reports for Unit 1 of the M.R. Young plant may not adequately represent the sulfur in coal fired in its combustion system. Nevertheless, the emission factor of 33.3S calculated from Gronhovd, et.al., data and the factor of 31.8S calculated from current CEM data are within 5 percent of one another. (See attached table.) Feed coal for Unit 1 of the M.R. Young plant has been and is obtained from the Center Mine, which is adjacent to the plant.

The data analysis above does not explain the CEM based sulfur dioxide emission factor of 40.7S for Unit 2 of the Leland Olds plant. The emission factor relies on data provided by the operator in annual emissions inventory reports. These reports indicate only lignite was used to fuel combustion systems. However, some Wyoming sub-bituminous coal was blended with lignite for use in Unit 2 after

mid-2001. The heat and sulfur contents of the sub-bituminous coal are different than local lignite; the heat content was about 8,000 Btu per pound, and the sulfur content ranged from 0.4 to 0.55 percent by weight. Because the heat content is higher and the sulfur content lower than local lignite, coal use data were reviewed by the operator to isolate those parts of the year when lignite only was used; a CEM based sulfur dioxide emission factor was calculated accordingly, but the result remained larger than 40S.

The sulfur contained in coal emerges – after combustion – in gas vented to the atmosphere and in fly ash, bottom ash or slag. Bulk analyses of fly and bottom ashes indicate that amounts of sulfur trioxide in these ashes varies widely. Data on amounts of ash after combustion and the amounts of sulfur trioxide in the ash can be used to estimate amounts of sulfur dioxide vented to the atmosphere. An example of such data are provided in the table at right; the data on coal ash content were obtained from Leland Olds plant personnel. If the sulfur trioxide data typify ashes for both boilers at the Leland Olds plant during years 2000 and 2001,¹⁰ about 21.2 percent of the coal sulfur content would have been retained in ash of Unit 1 and about 11.8 percent in the ash of Unit 2, which are equivalent to emission factors of 31.5S and 35.3S, respectively. Both factors are less than the CEM based factors shown in the attached table.

Sulfur contained in ash.

<u>Bulk Analysis</u>	<u>Fly Ash</u>	<u>Bottom Ash</u>
coal ash content (%)		
Leland Olds, Unit 1	5.6	2.4
Leland Olds, Unit 2	2.4	5.6
sulfur trioxide in ash (%)	6.0	1.0

Clearly, the CEM based emission factors of 37.4S for Unit 1 and 40.7S for Unit 2 of the Leland Olds plant are suspect, because sulfur is retained in boiler ash and slag.¹¹ As previously noted, the reported annual average coal sulfur content may not be representative of the coal burned during the current period. For example, if the reported year 2001 coal sulfur content for coal burned by Unit 2 was 0.76 percent as reported for Unit 1 (see attached table) rather than 0.67 percent, the calculated emission factor for Unit 2 would decrease from 42.5S to 37.5S. But, it is unlikely there is a bias in the average annual coal sulfur content for Unit 2 but not for Unit 1,

¹⁰ Sulfur trioxide contents, percent by weight, in ash for Unit 1 of the Leland Olds plant were: fly ash, 6.2; bottom ash 0.9. Sulfur trioxide contents for Unit 1 of the M.R. Young plant were: fly ash, 6.7; slag 0.1. (Pflughoeft-Hassett, Debra F., April 1996. Survey and Demonstration of Utilization Potential of North Dakota Lignite Ash Resources. Energy & Environmental Research Center, Grand Forks, North Dakota.)

¹¹ Relative Accuracy Test Audits of the CEM system for Leland Olds Unit 2 were conducted for years 2000 and 2001. System flow measurements were biased high by an amount greater than three percent for year 2001; no bias correction to CEM data was applied by the operator. Application of a bias correction to year 2001 CEM data would reduce the CEM based emission factor of 42.5S to 39.8S.

because emission factors would be similar and, thus, would not reflect the illustration above that ash produced by Unit 1 retains more coal sulfur than does the ash for Unit 2.

In summary, sulfur is retained in boiler ash or slag. Thus, the sulfur dioxide emission factor for Leland Olds Unit 2 could be 40.7S as an average for both years, if there is bias in CEM data and/or bias in reported coal sulfur content. Consequently, any adjustment to the factor for Unit 2 necessitates a corresponding adjustment to the current-period emission rate. As described above, larger factors are increasingly conservative.

In consideration of the information and data presented above, the alternate PSD baseline emission factors for baseline power plants are shown in the attached table. The sulfur dioxide emission factors in the attached table were used to calculate alternate baseline sulfur dioxide emission rates using baseline-period coal consumption and coal sulfur-content data. The baseline period is the two consecutive years representative of normal operations, as presented in Appendix D.

The baseline rate for Unit 2 of the Leland Olds plant has been adjusted from 7,690.3 lb/op-hr based on the factor's multiplier of 40.7 to 7,312.4 lb/op-hr based upon the factor's multiplier of 38.7. Consequently, the current period emission rate for this unit also has been adjusted from 8,566.0 lb/op-hr to 8,145.1 lb/op-hr.

At PSD baseline, Unit 2 of the Heskett plant was a pulverized lignite-fired boiler as was/is Unit 1. Thus, the PSD baseline emission factor for Heskett's Unit 2 is set to be the same as Unit 1. Feed coal for both units of the Heskett plant has been and is obtained from the Beulah Mine.

Data provided by Gronhovd, et.al., for Unit 1 of the M.R. Young plant as listed in the attached table, as well as other state lignite-fired units of power plants, are used.¹²

¹² The Wm.J. Neal plant also was sampled. This plant consisted of two pulverized coal-fired boilers; feed coal was obtained from the Velva Mine, which was located southwest of the plant. The sulfur dioxide emission factor was 32.9S pounds sulfur dioxide per ton coal (per data in table 3, Gronhovd, et.al.). This factor has been used to calculate the alternative baseline sulfur dioxide emission rate for the Neal plant.

The Beulah power plant was not sampled. The plant consisted of five units. Boilers 1, 2 and 3 were chain grate stokers, and boilers 4 and 5 were spreader stokers. An emission factor of 27.0S was used for boilers 4 and 5, as well as for boilers 1, 2 and 3. Boilers 4 and 5 were spreader stokers as is Unit 1 of the Heskett plant and boilers 3, 4 and 5 vented through a common stack as of the PSD minor source baseline date.

Calculated sulfur dioxide emission factors using 2000 and 2001 coal and emissions data.

Company / Plant	Current Boiler Type	Parameter *	Year 2000	Year 2001	Calculated Emission Factors ** (lb / ton)	Energy Research Lab. *** (lb / ton)	Alternative Baseline Emission Factor (lb / ton)
MDU / Heskett Unit 1	spreader stoker	coal burned (tons) average sulfur content (%) sulfur dioxide emissions (tons)	111,114 0.66 1,019	102,134 0.76 1,022	2000 - 27.8 2001 - 26.3 (ave. = 27.0)		27.0
MDU / Heskett Unit 2	fluidized-bed	coal burned (tons) average sulfur content (%) sulfur dioxide emissions (tons)	340,598 0.66 1,778	458,243 0.76 2,625	2000 - 15.8 2001 - 15.1 (ave. = 15.4)		27.0 (same as Unit 1)
Basin Electric / Leland Olds Unit 1	pulverized wall-fired	coal burned (tons) average sulfur content (%) sulfur dioxide emissions (tons)	1,302,256 0.68 16,864	1,093,610 0.76 15,237	2000 - 38.1 2001 - 36.7 (ave. = 37.4)	33.4	37.4
Basin Electric / Leland Olds Unit 2	cyclone	coal burned (tons) average sulfur content (%) sulfur dioxide emissions (tons)	2,140,601 0.69 28,587	2,546,797 0.67 36,219	2000 - 38.7 2001 - 42.5 (ave. = 40.7)		38.7 (yr 2000)
Minnkota / M.R. Young Unit 1	cyclone	coal burned (tons) average sulfur content (%) sulfur dioxide emissions (tons)	1,434,793 0.91 18,095	1,590,495 0.81 23,179	2000 - 27.7 2001 - 36.0 (ave. = 31.8)	33.3	33.3
Great River Energy / Stanton Unit 1	pulverized wall-fired	coal burned (tons) average sulfur content (%) sulfur dioxide emissions (tons)	666,577 0.64 7,660	744,341 0.72 9,424	2000 - 35.9 2001 - 35.2 (ave. = 35.5)		35.5
<p>* Amounts of coal burned and average sulfur content of that coal taken from annual emissions inventory reports. Amounts of emitted sulfur dioxide from CEM data as archived on EPA's Acid Rain Program data base.</p> <p>** Calculated emission factor equals sulfur dioxide emissions (as measured by CEM) divided by the product of the average sulfur content and the amount of coal burned.</p> <p>*** Gronhovd, G.H., et.al., May 1973, Some Studies on Stack Emissions from Lignite-Fired Power Plants, 1973 Lignite Symposium, May 9-10, 173, Grand Forks, North Dakota.</p>							

Appendix F – Oil and gas production source inventories.

Baseline sulfur dioxide emissions inventory

Emissions of SO₂ from oil and gas wells typically come from treaters or flares. Treaters separate the fluids in the crude oil for later transport or disposal. Flares burn the waste gas, converting the H₂S into SO₂. Since the mid-1980s, the Oil and Gas Division has been collecting well production data on the amount of wellhead gas flared monthly and the amount of wellhead gas used in firing the treater or other on-site equipment (lease use). These two monthly gas totals, the amount flared and the amount of lease use, were used by the Department of Health to calculate the SO₂ emissions from a well's flare and treater, respectively.

The Department has been requiring well operators to measure and report the H₂S content (percent) of the wellhead gas since the 1980s. The Department adds this data to a database controlled by the State's Oil and Gas Division. The H₂S data are generally not concurrent with the gas production data. In addition, H₂S data for many older wells are unreliable. No H₂S data exists for some wells; in these cases, it was necessary to substitute for the missing H₂S data from a nearby similar well.

A well's SO₂ emission rate is calculated by multiplying a monthly total of wellhead gas produced by the percent of H₂S in the gas and dividing by the number of days of production in the month (as well as some other conversion factors). Data from additional months were usually included to obtain an average emission rate over several months or a year.

The Oil and Gas Division believes the gas production data back to about 1987 are reliable. Early gas production data are considered somewhat unreliable because, until about the early to middle 1980s, the product of value from the wells was oil, and the gas was considered a waste product. Records were kept of oil production for the benefit of the owners, operators, and the State. However, the gas was a waste product disposed by flaring, etc., and data on gas production were not consistently and reliably reported or recorded until the value of the gas improved in the mid-1980s.

Some data on total wellhead gas production are available back to 1976-77, the two years before the baseline date, but the data often represent the amount of gas sold to a gas processing plant. The amount of wellhead gas used in the treaters or flared, which is necessary for emissions calculations, was not consistently reported before the mid-1980s and was available for a few wells in 1976-77. Based on the Oil and Gas Division's judgment that gas production data before 1987 were not completely reliable, the Department of Health used 1987-1988 gas production data to calculate an estimate of the baseline emission rate for wells that existed during the 1976-77 time period.

The Department previously conducted the “Williston Basin Regional Air Quality Study” (WBS, 1990). The Williston Basin Study processed oil and gas H₂S and production data for emissions data for all North Dakota wells producing during the period November 1987-March 1988. The emissions data from the 1987-88 study were applied to wells producing during 1976-77 as an estimate of baseline emissions. Well identifying information, such as the wells’ names, file numbers, field names, and locations for all wells producing during 1976-77 were extracted from the Oil and Gas Division database. Only wells that actually existed and were producing during 1976-77 were included in the baseline emissions inventory. For wells that existed in both time periods, the 1987-88 emissions data were used. For wells that produced in 1977 but not in 1987, there were no emissions data directly available. The average emission rate for all wells in the same field was calculated and substituted into the baseline inventory for each well of similar type, where data were available. In cases where data were needed for a 1977 well in a field that did not produce gas during 1987-88, a field-average emission rate from a similar, nearby field was used.

Much of the gas produced during 1987-88 was sold to gas processing plants and not flared. Many of these gas plants didn’t exist in 1976-77, so that all of that sold gas would have been flared. In cases where a 1977 well was not selling gas to a gas plant, all of the gas produced at that well in 1987, except for lease-use gas, would have been flared in 1977. The Williston Basin Study data were applied to these wells by adding the 1987-88 sold gas amount to the flared gas amount before calculating the flare emissions. Wells where gas was sold in both periods or where gas was not sold in both periods were assigned the Study’s flare emissions.

The remaining task was to determine which wells were selling gas in 1976-77. Gas processing plants receive gas from oil and gas wells through a pipeline, or gas-gathering system, that connects the wells to the gas plant. In 1977, the Tioga Gas Plant, near Tioga, was connected to the largest gas-gathering system in the state at the time, reaching from about 20 miles north of Tioga southward to southeastern McKenzie County southeast of Watford City. The Tioga pipeline connected to at least 20 separate oil and gas fields. The Lignite Gas Plant, near Lignite, was connected to a smaller gas-gathering system serving about nine fields in Burke County. Two small gas plants, the Red Wing Creek Gas Plant and the Boxcar Butte Gas Plant in western McKenzie County, also were operating in 1977 and received gas from only two isolated fields.

All other fields in the rest of the state were not served by any gas-gathering systems in 1977 and could not have sold gas. Later development in west-central North Dakota between Williston and Belfield triggered the construction of three additional gas plants and extensive gas-gathering systems in this area by 1987. Many wells in this part of western North Dakota were selling gas by 1987 where no gas plants existed in 1977.

When applying the above procedure for flare emission rates, it was assumed that any field connected to a gas-gathering system in 1977 was selling gas in 1977. Therefore, all wells in fields connected to the Tioga and Lignite gas-gathering systems and the Red Wing

Creek and Boxcar Butte gas plants were assumed to be selling gas both in 1976-77 and 1987-88 and so were assigned flare emission rates from the Williston Basin Study inventory. However, many other wells in western North Dakota were not connected to gas-gathering systems in 1977 and, thus, given credit for higher flare emissions in 1977 because of sold gas in 1987-88. The result of this procedure was an SO₂ emissions inventory for all oil and gas wells producing in 1976-77 that reflected gas production levels back to 1987, using the earliest reliable gas production data, and appropriately accounted for gas sold to gas processing plant.

Exception to baseline data and baseline inventory

The Department located gas production data for 1976-77 for a small number of wells in three oil and gas fields that appeared reliable, internally consistent, and reasonably complete for that period. Gas production data for 1976-77 exist for 29 wells in Little Knife Field, 2 wells in Elkhorn Ranch Field and 6 wells in Mondak Field. All three fields are in western North Dakota – partially within 50 km of Theodore Roosevelt National Park (TRNP). Little Knife Field is a large field more than 25 km southeast of the TRNP North Unit and mostly in western Dunn County. Elkhorn Ranch Field is a smaller field directly east of the TRNP Elkhorn Ranch Unit in northern Billings County. Mondak Field is another large field at least 30 km west of the TRNP North Unit in western McKenzie County. There were appropriate gas production data available for all Little Knife wells producing in 1976-77, for all three Mondak wells within 50 km of Class I areas, but not for most Elkhorn Ranch wells.

These data included all of the gas production data necessary for calculating an SO₂ emission rate as described earlier in this section, including monthly lease-use gas volumes, flared gas volumes and days of production. However, updated SO₂ emission rates were not included in the inventory for all wells in Little Knife, Elkhorn Ranch and Mondak Fields. The SO₂ emission rates for the Elkhorn Ranch and Mondak wells were relatively small and, thus, were not expected to greatly impact the results. Also, the Mondak wells were fairly distant from the Class I areas, located 30-50 km west of TRNP North Unit. It was concluded that the changes in the Elkhorn Ranch and Mondak source parameters would not significantly affect results of modeling analysis.

However, the baseline emission rates that are based on the Williston Basin Study data for the 29 Little Knife wells were relatively large and had a major impact on baseline concentrations at the Class I areas. Revised emission rates based on the 1976-77 gas production data could also be quite large and impact the results of the Class I modeling analysis. Therefore, baseline emission rates using the 1976-77 gas production data were calculated for the 29 Little Knife wells. Because the revised treater emission rates were very small, especially compared to the very large flare emission rates, only the updated flare emission rates were included. Revised values for the Little Knife flares' stack parameters were also calculated.

Previously, the Department modeled oil and gas well emissions based on the five-month average over the months November through March, but averaging over other periods has been considered. On the SO₂ baseline date, December 19, 1977, the Little Knife Field was in the middle of its initial development. Thirty-four wells were producing gas by the end of 1977 and many would be added later. The oldest Little Knife well produced on 224 days over 11 months in 1977. Most Little Knife wells produced on fewer days over 3-9 months of 1977. The newest baseline Little Knife well produced on only four days in December 1977. Clearly, the number of days and months of production were variable in 1977 and it would be difficult to define a representative period of emissions for all wells. Wells that produced for only a few days in December 1977 might have very different production or emission characteristics in 1977 from wells that produced most of the year.

A solution to the problem was to add additional months of gas production data in 1978, even though it was after the baseline date. This is justifiable because adding more months of production data produces more representative emission rates over the entire field that are more reflective of normal operations. However, the large amount of gas produced in Little Knife Field warranted the construction of a gas-processing plant. In 1978, Warren Petroleum Company, a Division of Gulf Oil Corporation, constructed the Little Knife Gas Plant to process the gas. Although the plant started receiving gas in July 1978, it was not fully operational until November 1978. Prior to the gas plant becoming fully operational much of the gas produced in Little Knife Field was flared (combusted).

In the interest of conserving the natural gas, at the March 28, 1978, Industrial Commission Hearing on Little Knife Field operations, Governor Arthur Link asked Gulf Oil Corporation, the operator of Little Knife Field, to voluntarily reduce the daily rate of production per well until the Little Knife Gas Plant began operations. In a letter to Governor Link dated April 6, 1978, Gulf Oil Corp. agreed to reduce the daily production rate of all wells in Little Knife Field to an average of 100 barrels of oil per day per well except for new wells undergoing initial production tests to evaluate the wells and reservoirs. The reduction was effective April 6, 1978 and continued until gas-handling facilities were in operation.

The period of reduced production from April until about November 1978, based on the Governor's request, does not represent normal operations for Little Knife Field and should not be included in the calculation of baseline emissions. Thus, baseline emissions for Little Knife wells were calculated as an average emission from the start of well production through March 1978. The number of months of data used in the calculation are often less than the difference between the last and first months, because at least one month of data is missing for each well. The result is that the Little Knife wells' baseline emission calculation included between three months of data and ten months of data depending on the well.

Other than the different gas production data and number of months, the emission calculation was the same as used before. The result of the revised calculation of Little Knife flare emissions is that the emission rates for some wells increased and some decreased, with about equal numbers of wells increasing as decreasing. However, the total baseline emissions (flares only) for the whole field increased about 9% from 935 grams/second to 1015 grams/second (1977-78 raw production data). Much of the increase in Little Knife Field emissions is due to these wells previously modeled at average emission rates. This suggests that the Little Knife Field average emissions were higher in 1977-78 than the Williston Basin Study data indicated.

Current period sulfur dioxide emissions inventory

The current period inventory of oil and gas production sources (flares and treaters) includes year 2000 source data only because of the man power effort required. Year 2000 actual emission rates reflecting annual average operation for oil and gas production sources were derived from the State Industrial Commission's (SIC) oil and gas data base. The data base includes information on gas production (flared and lease use), the H₂S content of the gas, such that SO₂ emission rates for well-site flares and treaters can be calculated. Dynamic stack operating parameters for these sources were derived from the calculated heat of combustion using procedures described in a previous report,¹³ and modified using SCREEN3¹⁴ adjustments for effective flare plume height and radiational heat loss. Flare and treater stack height were obtained directly from the SIC data base.

Flare and treater source inventory data

The sulfur dioxide emitted by those oil and gas production sources, flares and treaters, located within 50 kilometers of respective PSD Class I areas will be included as CALPUFF input data. Therefore, a separate modeling of each Class I area using only those sources within 50 kilometers of that area will be completed. Results at Class I area receptors from these modeling runs will be merged with results of modeling other sources using the program CALSUMOG.

A table of data for the number of flares and treaters located within 50 kilometers of each of the four PSD Class I areas in North Dakota and the total sulfur dioxide emissions of those flares and treaters follows on the next page below. Maps of the flares and treaters located within 50 kilometers of the North and South Units of TRNP are attached.

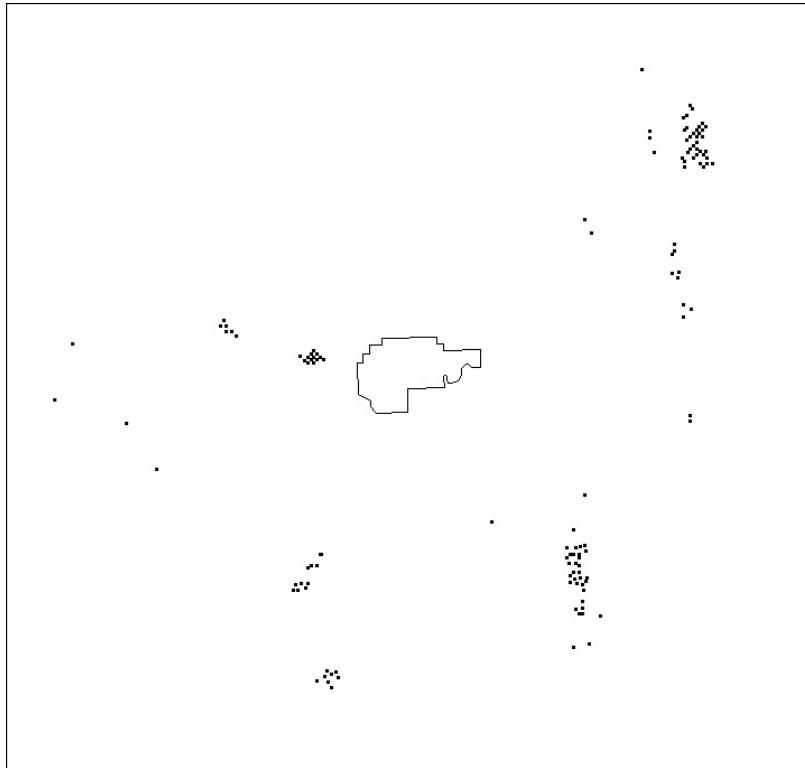
¹³ NDDH, 1990. Williston Basin Regional Air Quality Study. North Dakota Department of Health, Bismarck, North Dakota, 58506.

¹⁴ EPA, 1995. SCREEN3 Model User's Guide. Publication No. EPA-454/B-95-004, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711.

Statistical summary of oil and gas production sources located within 50 kilometers of PSD Class I areas. *				
	Baseline period		Current period	
Class I area	Number of sources	Total emission rate (pounds per hour)	Number of sources	Total emission rate (pounds per hour)
TRNP – South	196	824.6	262	318.3
TRNP – Elkhorn	248	8,030.1	310	460.6
TRNP – North	208	8,305.3	261	551.4
Lostwood WA	506	424.0	149	157.1
* Some sources are located within 50 kilometers of two or three TRNP areas and, therefore, are included in tabulated data for each area.				

Locations of flares and treaters within 50 kilometers of the North Unit of TRNP.

Baseline period



Current period



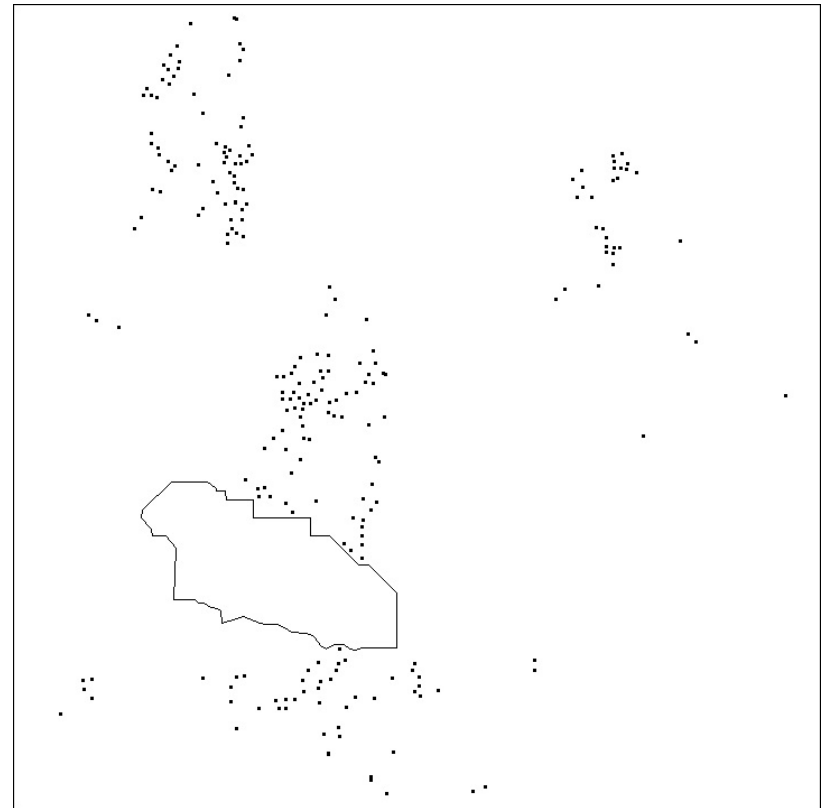
Locations of flares and treaters within 50 kilometers of the South Unit of TRNP.

Baseline period



0 10 20 30 40 km

Current period



0 10 20 30 40 km

Appendix G – Correspondence between emissions data and monitoring data.

The sulfur dioxide emission rate for each source used as input for the CALPUFF model in this protocol is not time variable but rather a constant that is applied 24/7/52 by the model. The emission rate for a source is often time variable, as illustrated by an attached figure which displays the total sulfur dioxide emitted by the coal-fired electric utilities in North Dakota for all 17,544 hours throughout years 2000 and 2001. Another figure enhances time resolution by displaying the total emitted sulfur dioxide each hour during the months of November 2000 through February 2001.

Actual emissions, which is the annual total emitted sulfur dioxide during operating hours as defined by rule, can be larger or smaller than the CEM measured rate for a specific hour. The sum of year 2000-2001 average actual emissions for the coal-fired electric utilities is also shown on the attached figure. The total hourly sulfur dioxide emitted by these sources exceeds the sum of actual emissions about 23.6 percent of the 17,544 hours during the two years.

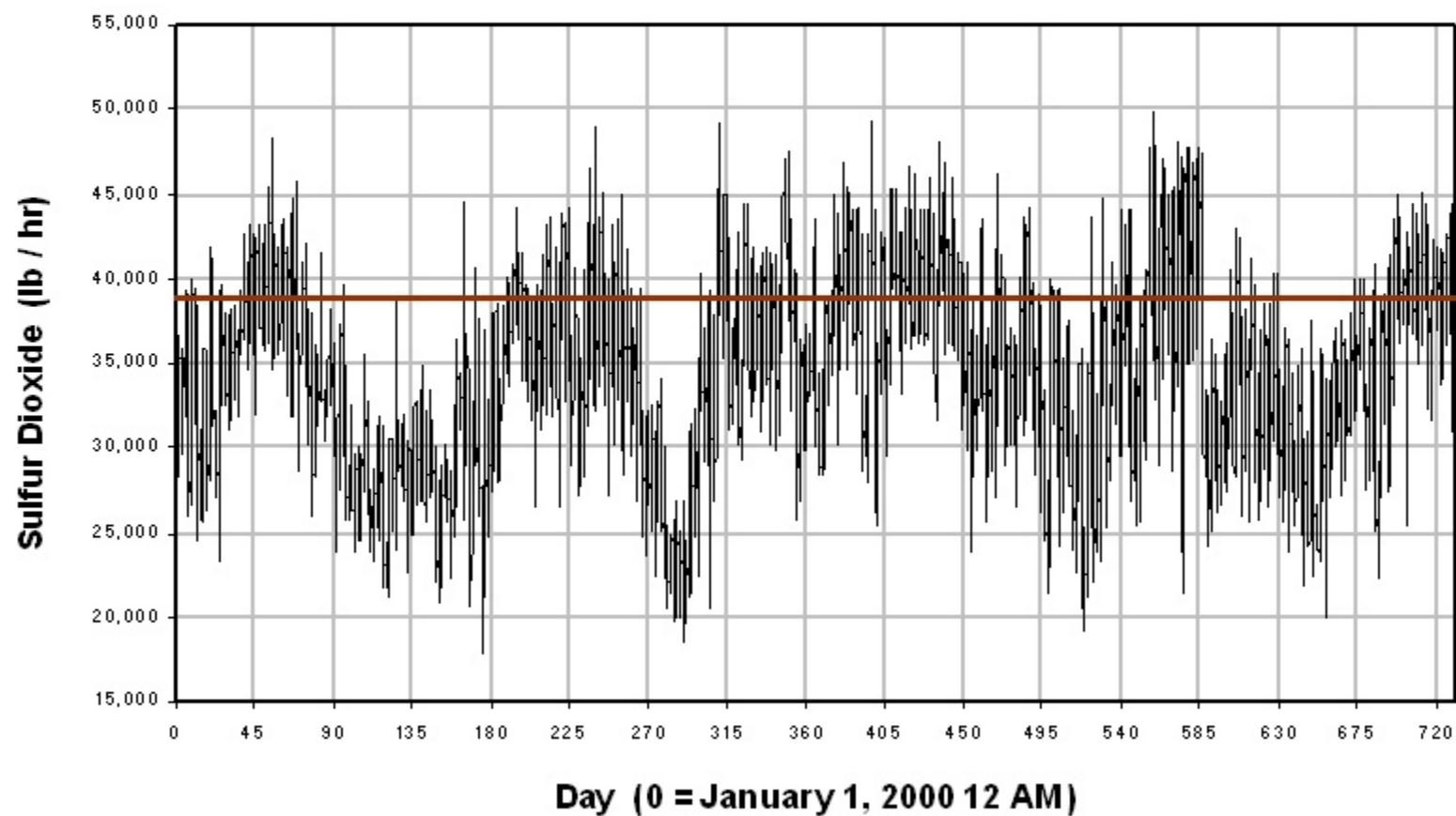
An estimate of the risk of under predicting actual observed sulfur dioxide concentrations at monitoring sites is the multiplication product of 23.6 percent and the frequency of easterly winds that could transport emitted sulfur dioxide westward and across PSD Class I areas. Based upon 900 millibar pressure altitude wind directions from NWS rawinsondes launched at Bismarck, the frequency of wind directions from east-northeast through southeast is about 15 percent. The calculated risk is about 3.5 percent. However, when emission rate inputs are actual emissions as previously indicated in the protocol, the CALMET and CALPUFF models over predict the highest actual observed sulfur dioxide concentrations.

Some sources are located at greater, or shorter, distances from PSD Class I areas than are other sources. Distances between sources, other than oil and gas production sources, and Class I areas range from about 30 kilometers to 200 or more kilometers. Therefore, the time of travel of emitted sulfur dioxide to PSD Class I areas varies among sources. The time of travel also depends on the speed of the wind. Two additional attached figures display hourly emitted sulfur dioxide and hourly sulfur dioxide concentrations at the monitoring site located in the South Unit of the TRNP. Only 1,796, or 10.2 percent, of the 17,544 hours during years 2000 and 2001 had concentrations larger than 1.5 parts per billion (ppb).

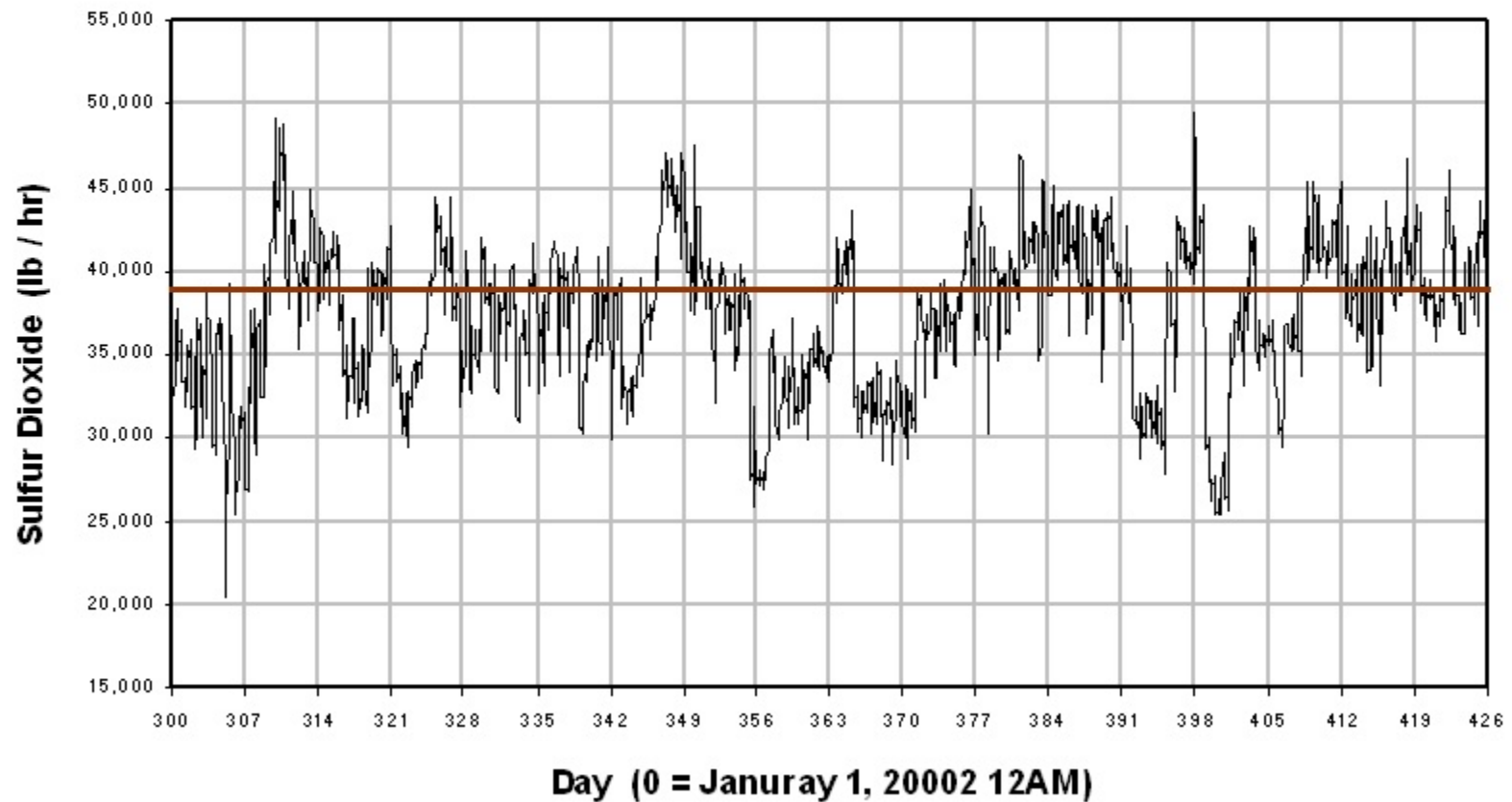
These figures illustrate an apparent chaotic association between amounts of sulfur dioxide emitted by the coal-fired electric utilities and actual observed concentrations at the TRNP-South Unit monitoring site. The apparent chaotic association is due to the range of distances of sources from the Class I area and to space and time variant conditions of the atmosphere during transport, dispersion and depletion of emitted sulfur dioxide that confound pairing the emitted sulfur dioxide with the concentrations.

Hourly CEM Sulfur Dioxide Emissions for Years 2000 and 2001 all North Dakota coal-fired electric utilities

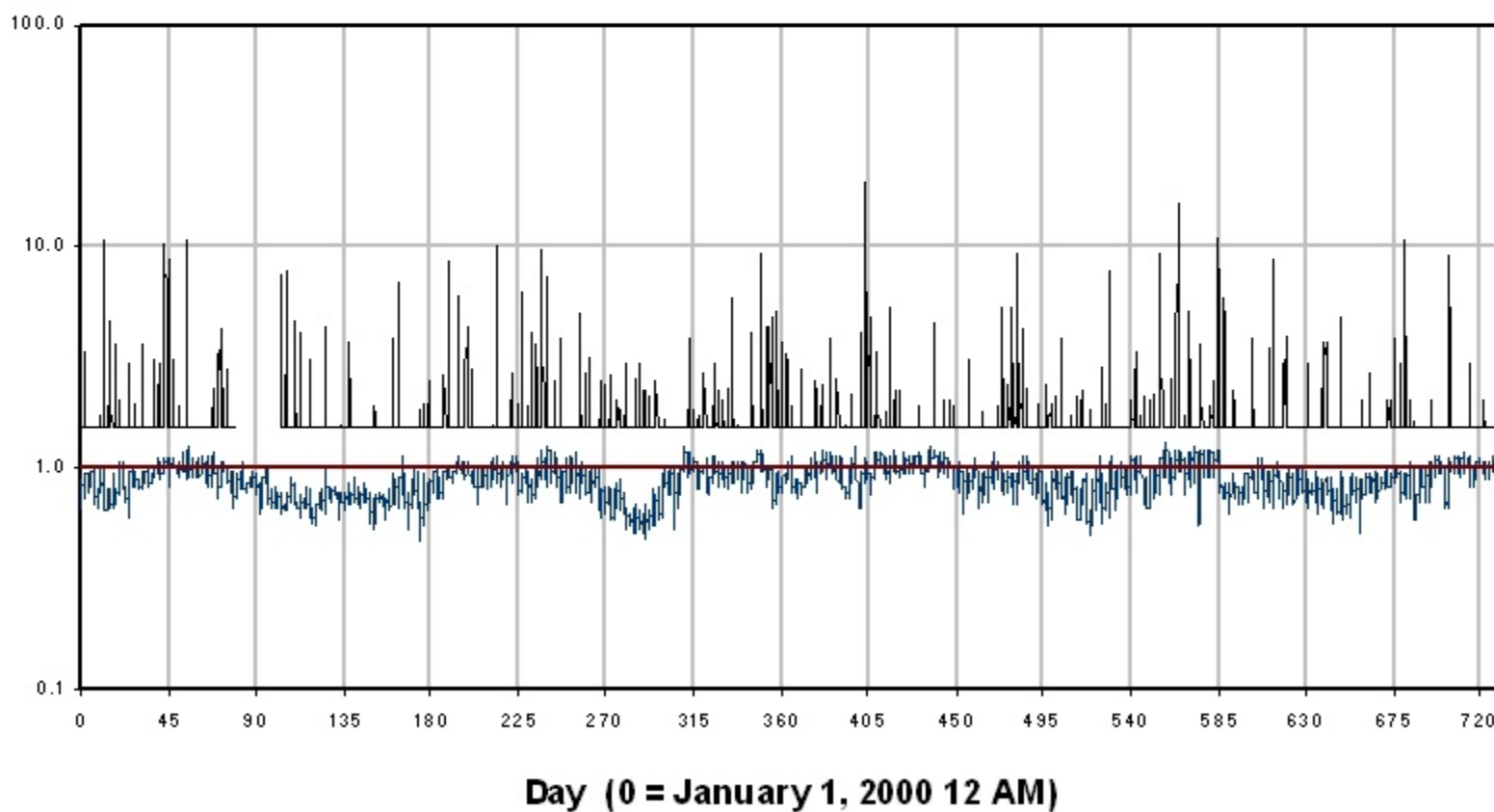
(The bar at 38,893 lb/hr is the sum of "actual emissions".)



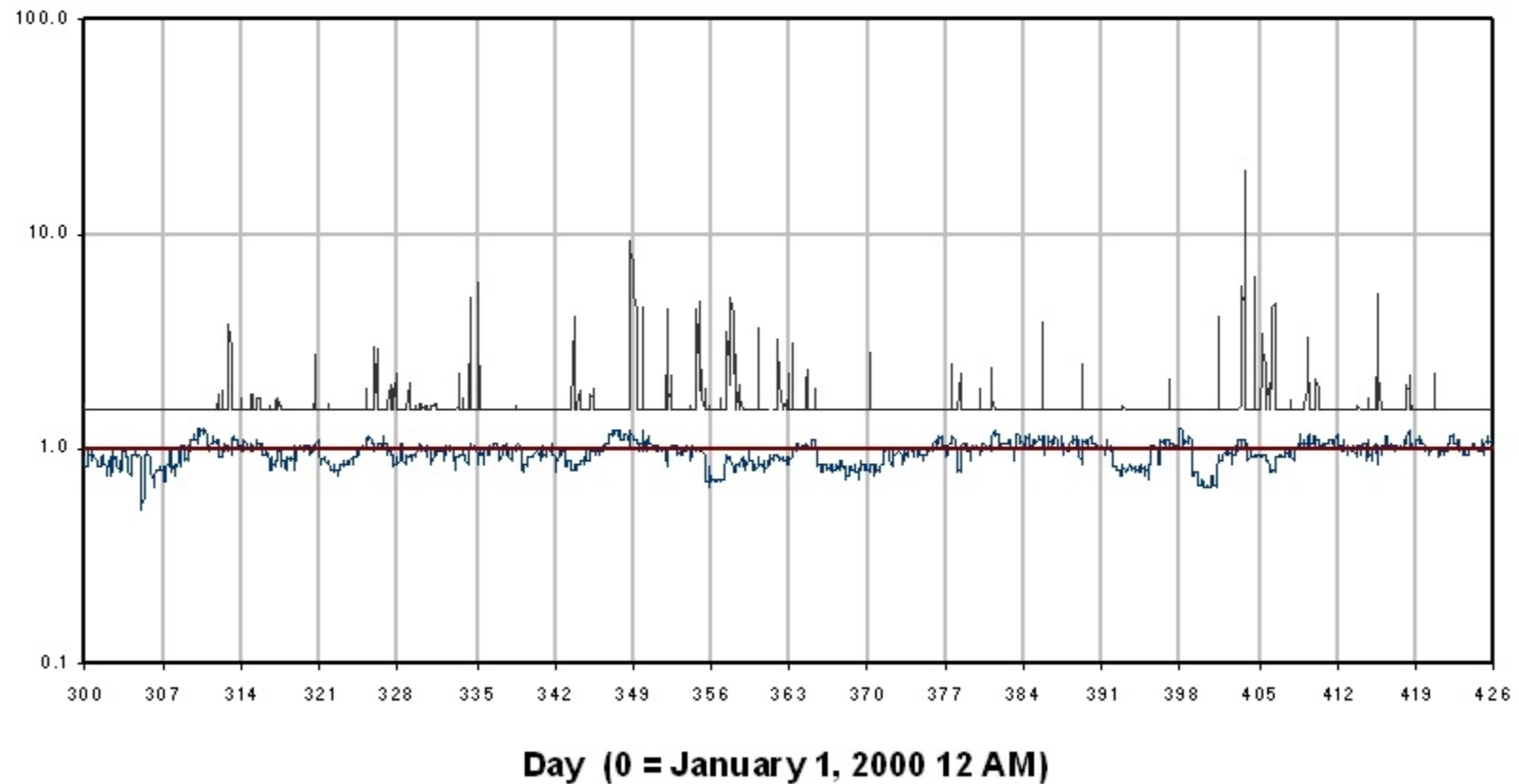
Hourly CEM Sulfur Dioxide Emissions
for the months of November 2000 through February 2001
all North Dakota coal-fired electric utilities
(The bar at 38,893 lb/hr is the sum of "actual emissions".)



**Hourly concentrations (ppb) of SO₂ at TRNP-South Unit (upper plot)
and hourly emitted SO₂ divided by actual emissions (lower plot)
for years 2000 and 2001.**



**Hourly concentrations (ppb) of SO₂ at TRNP-South Unit (upper plot)
and hourly emitted SO₂ divided by actual emissions (lower plot)
for the months of November 2000 through February 2001.**



Appendix H – Monitoring data for model accuracy tests.

The State Department of Health has compiled annual air quality monitoring data reports. These reports can be found at the following internet web addresses:

- 2000 http://www.health.state.nd.us/AQ/ambient/annual/ANN_00.pdf ,
2001 http://www.health.state.nd.us/AQ/ambient/annual/ANN_01.PDF , and
2002 http://www.health.state.nd.us/AQ/ambient/annual/ANN_02.PDF .

Model domain coordinates for monitoring sites

Ambient sulfur dioxide concentrations have been measured with monitors at two PSD Class I areas in western North Dakota. The remaining area of western North Dakota is a PSD Class II area. A monitor station is now located in each of the North and South Units of the TRNP, and two monitors are located east of these Units. The monitor station at the North Unit was operating throughout the years 1990 through 1994 and also after August 2001. The monitor station at the South Unit was operating throughout the years 2000 and later. Monitor stations were operating at rural Dunn Center and rural Hannover throughout the years 1990 through 1994 and 2000 through 2002. The lower detection level of sulfur dioxide monitoring instruments decreased from 2 parts per billion to 1 part per billion (2.6 micrograms per cubic meter) after 1994 and prior to 2000.

A model receptor will be placed at the location of monitors. Model predicted concentrations at these receptors will be used for accuracy tests; these predicted concentrations will not be used for calculation and tabulation of PSD increment exceedances.

Coordinates for locations of sulfur dioxide monitoring sites.					
Monitor location	County	Longitude (degrees)	Latitude (degrees)	Terrain elevation (meters)	Number of nearest Class I area receptor
TRNP – South Unit	Billings	103.3731	46.8928	832	108
TRNP – North Unit	McKenzie	103.2643	47.6018	612	114
rural Dunn Center	Dunn	102.5263	47.3202	683	not applicable
rural Hannover	Oliver	101.4281	47.1858	697	not applicable

Highest 24-hour sulfur dioxide values

Hourly concentration data have been block averaged for each sequential 24-hour block – midnight to midnight Mountain Standard Time, throughout the year for 2000, 2001 and 2002. The 366, or 365, 24-hour averages were then ranked from the highest value to the lowest value. The 40 highest values are provided in attached tables.

The 24-hour concentration data in the attached table reflect the measured consequence of all emitted sulfur dioxide, including any deterioration since PSD baseline more than 23 years earlier. Color shaded data in the table are greater than PSD sulfur dioxide 24-hour increments of 5 ug/m³ and 25 ug/m³, respectively, for PSD Class I and Class II areas. For example, the data indicate that only thirteen of 366 daily concentrations for year 2000 were larger than the 24-hour increment. The sulfur dioxide deterioration cannot exceed these monitored (total) concentrations, and it would equal these monitored concentrations only if there was no background concentration and no sources of sulfur dioxide in the modeling domain at PSD baseline. However, there were many sources at PSD baseline.

Two factors relate to the choice of the number of highest values to include in model accuracy tests.

- ✓ The lower useable detection level is 1 part per billion for analytical methods that use the hourly sulfur dioxide concentration data, such as 3-hour, 24-hour and annual averaging. However, the lowest useable detection level for other analytical methods that do not average the hourly concentration data is 1.5 parts per billion.¹⁵
- ✓ The range of baseline concentrations and range of current concentrations for those changes in concentration that exceed (deterioration as ΔX) an increment are normally not tabulated and reported. These exceedances may not pair with the highest current concentrations.

Thus, model accuracy tests of model predicted 24-hour concentrations in PSD Class I areas will be confined to use of the 25, or fewer, highest values provided in the attached tables.

¹⁵ The field instruments for measuring ambient sulfur dioxide are pulsed fluorescence sulfur dioxide analyzers. The instruments are operated in the 60 second averaging time mode. When the instruments are operating in this mode, the zero noise range is 0.5 parts per billion and the lower detection level is 1.0 part per billion. (See operating Instruction Manual P/N 9997 for Model 43C by Thermo Environmental Instruments, Inc., page 1-3.) However, span calibrations of the instruments have been performed at increments of whole number concentrations starting at 2 parts per billion.

A mathematical estimate of baseline concentrations

The second highest 24-hour monitored concentrations in the South Unit of TRNP, which are provided on attached tables, were: for year 2000, 9.39 ug/m³; 2001, 8.81 ug/m³; and 2002, 8.30 ug/m³. Since no monitoring data are available preceding 1980, the 24-hour monitored concentrations for this and other PSD Class I areas at PSD baseline are not known.

Two mathematical methods for determining baseline concentrations are provided in this alternate protocol. Under the first method, which also is the method of prior protocols, the baseline concentration would have been the concentration occurring on the same Julian day of modeled meteorological data, which represents the weather during the baseline year(s).¹⁶ Under the second method, the baseline concentration is the second-highest concentration throughout the year(s) of modeled meteorological data, which also represents the weather during the baseline year(s). If baseline monitoring data were available, deterioration that exceeds the PSD Class I 24-hour sulfur dioxide increment of 5 ug/m³ and that pushes ambient concentrations to the level of the current second highest 24-hour concentration of 9.39 ug/m³ would have had to be begin at a baseline concentration of 4.39 ug/m³ or smaller.

Is a baseline concentration of 4.39 ug/m³ or smaller reasonably feasible? An inventory of emitted sulfur dioxide was assembled for a current period. The ratio of 4.39 ug/m³ and 9.39 ug/m³ is 0.478. The sum of rates of emitted sulfur dioxide for sources at current period is 43,439.2 pounds per hour. A crude guess of emissions during PSD baseline that might have resulted in significant deterioration is the multiplication product of the ratio 0.478 and 43,658.2 pounds per hour, which is 20,868.6 pounds per hour and which is significantly less than the sum of 29,683.9 pounds per hour pursuant to his protocol.

What might have been the baseline concentration? The sum of estimated emission rates during PSD baseline pursuant to this protocol is 67.8 percent of the sum of current rates. These sums do not include the numerous oil and gas production sources; there were about 300 fewer of these sources during the current period. A crude guess of the baseline concentration at the location of the monitor in the South Unit of TRNP can be calculated as the multiplication product of the ratio of 0.678 and the second highest monitored

¹⁶ When modeling baseline and current emission inventories, the meteorology throughout a modeled year is the same. EPA's current method of determining deterioration in time as well as in space cannot be duplicated with monitoring data. Comparison of monitoring data on a Julian day during current period year(s) to monitoring data on the same Julian day during PSD baseline year(s) as a measure of deterioration presumes that the weather was the same on that day during both time periods. Identical weather on the same Julian day during both time periods is extremely unlikely. If two or more years of baseline monitoring data had been available, how would the data be used in combination with current monitoring data to mathematically determine the deterioration occurring since baseline? One answer is the alternate mathematical method provided by this protocol.

concentration for each current-period year of monitoring data. Thus, a crude guess of baseline concentrations for the Julian day of the second-highest event or for the calendar year is: from data for year 2000, 6.37 ug/m³; 2001, 5.97 ug/m³; and 2000, 5.63 ug/m³.

The observation or conclusion emerging from this exercise is that the alternate modeling protocol must be sufficiently robust so as to confidently resolve the amounts of ambient sulfur dioxide deterioration occurring over the 26 years after 19 December 1977, which is the PSD minor source baseline date.

Table of 24-hour averaged sulfur dioxide concentrations at four monitoring locations for years 2000, 2001 and 2002.													
Year 2000													
PSD Class I areas													
PSD Class II area													
TRNP-NU													
TRNP-SU													
Dunn Center													
Hannover													
Rank	ppb	ug/m3	J. Date	ppb	ug/m3	J. Date	ppb	ug/m3	J. Date	ppb	ug/m3	J. Date	
1				3.71	9.72	46	7.75	20.31	350	11.58	30.35	31	
2				3.58	9.39	44	7.54	19.76	348	11.17	29.26	71	
3				2.83	7.42	350	6.17	16.16	238	10.50	27.51	208	
4				2.50	6.55	349	4.54	11.90	43	10.21	26.75	234	
5				2.33	6.11	237	4.00	10.48	11	8.29	21.72	260	
6		no		2.27	5.95	54	3.88	10.15	65	7.96	20.85	195	
7				2.21	5.79	11	3.88	10.15	349	7.64	20.01	228	
8		data		2.17	5.68	106	3.71	9.72	184	7.29	19.10	217	
9				2.13	5.57	43	3.42	8.95	106	7.04	18.45	194	
10		for		2.13	5.57	238	3.38	8.84	31	6.92	18.12	69	
11				2.04	5.35	358	3.29	8.62	358	6.33	16.59	43	
12		year		2.00	5.24	214	3.21	8.41	76	6.13	16.05	147	
13				1.96	5.13	47	3.17	8.30	247	6.08	15.94	104	
14		2000		1.83	4.80	257	3.04	7.97	214	6.08	15.94	237	
15				1.79	4.69	355	2.96	7.75	45	5.88	15.39	187	
16				1.75	4.59	19	2.88	7.53	244	5.50	14.41	41	
17				1.75	4.59	104	2.71	7.10	359	5.38	14.08	161	
18				1.75	4.59	331	2.64	6.91	12	5.29	13.86	222	
19				1.75	4.59	336	2.42	6.33	15	5.29	13.86	350	
20				1.71	4.48	228	2.41	6.31	40	5.04	13.21	202	
21				1.63	4.26	15	2.38	6.22	152	4.79	12.55	67	
22				1.63	4.26	335	2.38	6.22	228	4.71	12.34	42	
23				1.63	4.26	353	2.38	6.22	363	4.71	12.34	97	
24				1.58	4.15	164	2.29	6.00	345	4.64	12.15	61	
25				1.54	4.04	31	2.21	5.79	5	4.63	12.12	119	
26				1.54	4.04	110	2.21	5.79	47	4.58	12.01	171	
27				1.54	4.04	190	2.21	5.79	69	4.58	12.01	346	
28				1.54	4.04	199	2.17	5.68	46	4.55	11.91	257	
29				1.54	4.04	359	2.13	5.57	2	4.50	11.79	66	
30				1.50	3.93	313	2.13	5.57	44	4.46	11.68	220	
31				1.50	3.93	332	2.09	5.48	320	4.46	11.68	301	
32				1.50	3.93	356	2.08	5.46	360	4.46	11.68	334	
33				1.50	3.93	363	2.05	5.36	187	4.42	11.57	366	
34				1.46	3.82	241	2.04	5.35	74	4.38	11.46	196	
35				1.46	3.82	288	2.04	5.35	351	4.33	11.35	351	
36				1.42	3.71	126	2.00	5.24	356	4.25	11.14	340	
37				1.42	3.71	328	1.96	5.13	19	4.13	10.81	163	
38				1.38	3.60	16	1.96	5.13	199	4.09	10.72	201	
39				1.38	3.60	71	1.96	5.13	366	4.08	10.70	49	
40				1.38	3.60	189	1.92	5.02	49	4.08	10.70	105	

Year 2001		PSD Class I areas						PSD Class II area					
		TRIIP-HU			TRIIP-SU			Dunn Center			Hannover		
Rank		ppb	ug/m3	J. Date	ppb	ug/m3	J. Date	ppb	ug/m3	J. Date	ppb	ug/m3	J. Date
1		2.38	6.24	345	3.96	10.37	38	5.21	13.65	45	15.96	41.81	24
2		1.92	5.02	274	3.36	8.81	198	4.77	12.50	190	9.79	25.65	84
3		1.71	4.48	362	3.29	8.62	219	3.75	9.83	57	9.17	24.02	116
4		1.63	4.26	361	3.21	8.41	315	3.21	8.41	42	7.17	18.78	13
5		1.58	4.15	346	2.82	7.38	190	3.21	8.41	56	6.88	18.01	145
6		1.54	4.04	310	2.50	6.55	316	3.21	8.41	58	6.79	17.79	91
7		1.50	3.93	364	2.21	5.79	41	3.17	8.30	44	5.63	14.74	41
8		1.42	3.71	328	2.21	5.79	116	3.08	8.08	178	5.58	14.63	81
9		1.38	3.60	258	2.14	5.60	339	3.08	8.08	205	5.38	14.08	333
10		1.38	3.60	297	2.08	5.46	220	2.96	7.75	195	5.25	13.76	316
11		1.33	3.49	246	2.04	5.35	112	2.96	7.75	258	5.17	13.54	154
12		1.25	3.28	365	2.00	5.24	338	2.75	7.21	177	5.00	13.10	87
13		1.23	3.22	243	1.92	5.02	223	2.58	6.77	220	5.00	13.10	112
14		1.21	3.17	272	1.88	4.91	40	2.54	6.66	50	4.86	12.74	338
15		1.21	3.17	314	1.86	4.88	176	2.50	6.55	109	4.83	12.66	10
16		1.19	3.12	275	1.83	4.80	118	2.46	6.44	32	4.75	12.45	63
17		1.17	3.06	298	1.83	4.80	275	2.33	6.11	41	4.63	12.12	159
18		1.17	3.06	341	1.75	4.59	163	2.25	5.90	38	4.54	11.90	327
19		1.16	3.03	360	1.71	4.48	108	2.25	5.90	64	4.54	11.90	330
20		1.14	2.99	332	1.67	4.37	50	2.25	5.90	310	4.50	11.79	149
21		1.13	2.95	237	1.67	4.37	211	2.21	5.79	15	4.38	11.46	111
22		1.13	2.95	249	1.67	4.37	247	2.21	5.79	55	4.21	11.03	12
23		1.13	2.95	266	1.58	4.15	44	2.17	5.68	31	4.17	10.92	123
24		1.08	2.84	239	1.58	4.15	117	2.17	5.68	43	4.13	10.81	73
25		1.08	2.84	256	1.54	4.04	175	2.17	5.68	247	4.08	10.70	97
26		1.08	2.84	265	1.54	4.04	216	2.13	5.57	11	3.88	10.15	75
27		1.08	2.84	288	1.50	3.93	119	2.13	5.57	112	3.79	9.93	150
28		1.08	2.84	350	1.50	3.93	133	2.08	5.46	2	3.73	9.77	144
29		1.08	2.84	355	1.50	3.93	218	2.04	5.35	46	3.71	9.72	93
30		1.08	2.84	357	1.46	3.82	39	1.96	5.13	49	3.50	9.17	139
31		1.05	2.74	261	1.46	3.82	160	1.96	5.13	346	3.46	9.06	57
32		1.04	2.73	254	1.42	3.71	73	1.92	5.02	148	3.42	8.95	42
33		1.04	2.73	255	1.42	3.71	205	1.92	5.02	224	3.42	8.95	62
34		1.04	2.73	299	1.42	3.71	237	1.83	4.80	219	3.38	8.84	155
35		1.04	2.73	316	1.41	3.69	121	1.83	4.80	345	3.38	8.84	340
36		1.04	2.73	331	1.41	3.69	282	1.78	4.67	24	3.25	8.52	67
37		1.04	2.73	334	1.38	3.60	109	1.75	4.59	20	3.25	8.52	315
38		1.04	2.73	340	1.33	3.49	20	1.75	4.59	39	3.21	8.41	359
39		1.04	2.73	348	1.33	3.49	222	1.75	4.59	48	3.17	8.30	74
40		1.04	2.73	358	1.33	3.49	310	1.75	4.59	260	3.17	8.30	167

Year 2002	PSD Class I areas						PSD Class II area					
	TRIIP-HU			TRIIP-SU			Dunn Center			Hannover		
Rank	ppb	ug/m3	J. Date	ppb	ug/m3	J. Date	ppb	ug/m3	J. Date	ppb	ug/m3	J. Date
1	3.42	8.95	73	4.75	12.45	248	3.46	9.06	26	14.13	37.01	205
2	2.88	7.53	66	3.17	8.30	297	3.42	8.95	293	9.88	25.87	211
3	2.42	6.33	83	3.04	7.97	28	3.10	8.11	28	8.19	21.46	70
4	2.25	5.90	80	2.79	7.31	141	2.96	7.75	187	7.92	20.74	51
5	1.92	5.02	39	2.67	6.99	283	2.79	7.31	66	7.54	19.76	81
6	1.92	5.02	95	2.63	6.88	26	2.79	7.31	95	7.00	18.34	49
7	1.82	4.76	78	2.46	6.44	29	2.50	6.55	173	6.79	17.79	230
8	1.67	4.37	29	2.38	6.22	49	2.46	6.44	83	6.21	16.27	22
9	1.67	4.37	92	2.38	6.22	247	2.45	6.43	153	5.92	15.50	82
10	1.64	4.29	302	2.25	5.90	64	2.33	6.11	198	5.87	15.38	160
11	1.63	4.26	69	2.21	5.79	235	2.29	6.00	234	5.42	14.19	72
12	1.63	4.26	293	2.17	5.68	241	2.25	5.90	184	5.25	13.76	136
13	1.63	4.26	337	2.17	5.68	292	2.17	5.68	69	5.21	13.65	39
14	1.58	4.15	79	2.08	5.46	236	2.13	5.57	73	5.17	13.54	137
15	1.58	4.15	116	2.08	5.46	243	2.00	5.24	27	4.96	12.99	95
16	1.54	4.04	153	2.08	5.46	244	2.00	5.24	80	4.88	12.77	23
17	1.54	4.04	339	2.08	5.46	249	1.96	5.13	294	4.71	12.34	199
18	1.52	3.99	149	2.08	5.46	250	1.88	4.91	174	4.63	12.12	158
19	1.5	3.93	18	2.04	5.35	238	1.83	4.80	189	4.54	11.90	105
20	1.5	3.93	77	2.00	5.24	173	1.79	4.69	39	4.50	11.79	204
21	1.5	3.93	294	2.00	5.24	237	1.75	4.59	100	4.00	10.48	358
22	1.46	3.83	216	2.00	5.24	240	1.71	4.48	65	3.92	10.26	312
23	1.46	3.82	363	1.96	5.13	239	1.71	4.48	68	3.83	10.04	52
24	1.42	3.71	5	1.96	5.13	242	1.71	4.48	75	3.71	9.72	79
25	1.42	3.71	74	1.96	5.13	251	1.71	4.48	116	3.71	9.72	97
26	1.38	3.60	122	1.95	5.12	296	1.71	4.48	336	3.67	9.61	182
27	1.38	3.60	336	1.92	5.02	78	1.67	4.37	137	3.67	9.61	296
28	1.38	3.6	353	1.83	4.80	234	1.67	4.37	216	3.67	9.61	310
29	1.38	3.6	357	1.83	4.80	252	1.67	4.37	248	3.63	9.50	26
30	1.33	3.49	17	1.83	4.80	255	1.63	4.26	78	3.54	9.28	300
31	1.33	3.49	70	1.79	4.69	246	1.63	4.26	139	3.46	9.06	152
32	1.33	3.49	81	1.75	4.59	66	1.58	4.15	81	3.46	9.06	295
33	1.33	3.49	138	1.75	4.59	289	1.58	4.15	301	3.38	8.84	206
34	1.33	3.49	139	1.75	4.59	290	1.58	4.15	338	3.38	8.84	210
35	1.29	3.38	11	1.71	4.48	253	1.54	4.04	122	3.33	8.73	188
36	1.29	3.38	28	1.67	4.37	80	1.54	4.04	319	3.25	8.52	126
37	1.29	3.38	61	1.67	4.37	82	1.50	3.93	127	3.21	8.41	124
38	1.29	3.38	75	1.54	4.04	67	1.50	3.93	152	3.21	8.41	184
39	1.29	3.38	184	1.54	4.04	293	1.50	3.93	199	3.21	8.41	365
40	1.29	3.38	187	1.50	3.93	27	1.50	3.93	247	3.17	8.30	78

BLANK PAGE